ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 1:

Volume 3 PDF p. 118, lines 22-25 and PDF p. 119, lines 1-14

G. BENTIVEGNA: In terms of the IPP, the board had -- IPP programs, the board has some questions that in the interests of time, to use the time, the hearing time efficiently, is providing to AEY in written form. And that -- and we'll be putting those questions on our website. And if those questions -- if AEY is able to answer those questions, then there is no need for the undertaking to respond to the undertaking given to Mr. Fortin on IPPs and agreements. So I just wanted to put that on the proceeding record, that you'll be seeing that. And that those -- the responses to those written questions will be filed with the undertake -- the other undertakings on December 4th. So if AEY is fine with that, then we'll proceed that way.

J. MASSIE: Yes. We -- yeah. We'll understand the questions that the board has, and we'll endeavour to answer all those. Having a quick look at them, looks like we'll be able to get those promptly.

Request:

On Tuesday, November 28, 2023 testimony, Jay Massie, referred to a maximum that the IPPs were allowed to supply on the isolated grids.

(a) Question: For each of the individual isolated grids, what is the average summer generator capacity required to maintain reliable service?

(b) Question: For each of the individual isolated grids, what is the maximum electrical supply that an IPP can supply without storage and without de- stabilizing the micro grid?

(c) Question: For each of the individual isolated grids, what is the capacity in kW.h of the BESS and how was this capacity established?

(d) Question: For each of the individual isolated grids, what is the capacity of the microgrid controller (MGC) and how was this capacity established?

(e) Question: For an IPP, generally where is the point on interconnection?

(f) Question: What factors determine the location of the point of interconnection?

(g) Question: If a battery allows the IPP to generate more energy hence more revenues, why should AEY be responsible for the O&M of the battery?

(h) Question: What is the historical expenditure for the maintenance of the MGC?

(i) Question: What is the historical expenditure for the maintenance of the BESS?

(j) Question: For each of the individual isolated grids, does AEY carry insurance on the MGC and BESS?

(k) Question: For each of the individual isolated grids, what is the annual cost of such insurance?

(l) Question: For each of the individual isolated grids, what is the efficiency of the battery system?

(m) Question: For each of the individual isolated grids, does the IPP or AEY bear the cost of the losses associated with the overall IPP installation including the battery systems?

(n) Question: For each of the individual isolated grids, please quantify the expected monetary value of the losses for the Test Years.

(o) Question: For each of the individual isolated grids, does AEY have any involvement AEY into the specifications and procurement of the major components (MGC and BESS)? If so, describe the involvement that AEY has into the specifications and procurement of the major components (MGC and BESS)[F}

Reference: Application Schedule 3.1 line 2. - Average price of electricity purchase 0.74 cent / kW.h.

(p) Question: How was the average price determined? Does this represent an average for all IPPs? Are there different rates paid to different IPPs?

(q) Is the average electricity purchase cost a "pure" energy charge? That is does it does it include additional items such as constraint payments?

(r) For each of the individual isolated grids, What rate schedule applies to the energy consumed by the IPP at the POI?

AEY Responses:

(a) Typically, under normal system conditions, AEY sees the lowest system loads during the summer period. Typically, these loads are supplied by the smallest unit or combination of units.

Table 1: Average Summer Generation Capacity (kW)

Community	Average Summer Generation Capacity (kW)
Beaver Creek	285
Destruction Bay	312
Old Crow	400
Watson Lake	1,700

(b) The limits for unregulated non-dispatchable IPP generation into AEY's remote systems have been established as AEY's system limits for Micro-Generation, as outlined in the following table.

Table 2: Micro-Gen Unregulated Renewable Limits (kW)

Community	Micro-Gen // Unregulated Renewable Limits (kW)
Beaver Creek	57
Destruction Bay	62
Old Crow	80
Watson Lake (Total Micro-Gen and SOP)	150

(c) The currently selected and proposed BESS sizes in kWh are as follows:

Table 3: BESS Capacity (kWh)

Community	BESS Capacity (kWh)
Beaver Creek	3562 – Purchased
Destruction Bay	713 – Purchased
Old Crow	616 – Installed
Watson Lake	3,000 – Proposed

Sizing of the BESS is primarily determined by the IPP during the design of their renewable generation project. In AEY systems, IPP generation allows for diesel off operation. As such, AEY has established a minimum BESS capacity based on the one-hour minimum of peak load expected during the months in which diesel off operation is expected to occur. This allows AEY one hour to establish diesel generation, from cold start, if renewable generation is interrupted.

(d) MGC refers to control equipment required to establish overall system coordination between existing equipment (diesel generators and feeders) and new assets (IPP generation and BESS) to ensure safe and reliable service to customers. The MGC does not have a specific capacity in terms of electrical values like power or energy.

(e) For AEY's remote community IPP projects, the point of interconnection is the secondary terminals of the transformer required to interconnect the IPP to the distribution system. Please also refer to Transcript Vol. 3, PDF p. 40, lines 3-11 and 19-25 and PDF p. 41, lines 1-9 and 14-16.

(f) The approach to determine the point of interconnection for these projects, being the secondary terminals of the transformer, is the same approach AEY currently uses for commercial projects. This approach aligns with the Board approved Terms and Conditions section 3.3 Ownership of Facilities.

(g) AEY owns the BESS and MGC because they are grid-forming equipment. The BESS, during diesel off scenarios, is responsible for management of system voltage and frequency which is a utility responsibility. The MGC is responsible for system coordination between AEY's power plant and the IPP's renewable generation site.

Accordingly, AEY is responsible for the O&M of this equipment just as it is for any other equipment and infrastructure associated with providing utility service to customers. This aligns with OIC 2019-25,[1] which states that the Board must allow the utility to recover:

> *"the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement."*

(h-i) These are new assets to AEY, and it will take three to five years of operation to determine a baseline for O&M costs for these new assets. To date, AEY can identify that a two-year service contract with the MGC and BESS supplier for Old Crow has a cost of $65,000 USD.

(j) Yes, these assets are included under the insurance coverage provided for the diesel plant installed in each community.

(k) The increase in site costs due to BESS and MGC installation results in an incremental cost increase to site premiums. Please refer to Table 4 below for Old Crow insurance premiums. Old Crow is the only operating isolated IPP at this time and is the only one covered by AEY's insurance.

[1] OIC 2019-25, Section 2, Subsection 2, PDF page 3-4.

Table 4: Insurance Premiums

($)

Old Crow	TIV	Premium	Delta
2020	10,323,859	13,065	-
2021	10,586,624	14,108	1,043
2022	15,850,929	21,410	7,302

(l) The designed round-trip efficiency for the BESS units purchased is 85 percent.

(m) For IPP power production in isolated grids, metering of IPP sales is measured on the high voltage side of the transformer. The IPP proponent is responsible for losses on the customer side of the meter, including the transformer losses and the renewable generation site losses.

BESS losses are contingent on the installed location of the BESS in relation to the power system. For the Beaver Creek IPP project, the BESS is installed at the PV site on the customer side of the meter where the IPP will be responsible for losses. For the Destruction Bay and Old Crow IPP projects, the BESS is installed at or near AEY's power plant site which is remote from the renewable generation site. The BESS losses are part of AEY's power plant in these communities. The Watson Lake BESS location is not finalized.

(n) AEY has not completed a loss study for the isolated grids. It is a complex model and long-term operational data is required to quantify the effect of the IPP on grid losses.

(o) After a competitive procurement process, approved by the project funding agencies and proponents, one supplier was selected to standardize the MGC and BESS for all the isolated grids across the Yukon. AEY works with the IPP to determine the sizing of the BESS and is responsible' with support from the IPP, for creating the specifications required for the purchase of these assets. AEY then reviews the submission supplied by the vendor with the IPP proponents to work towards the final purchase.

(p) The average price was determined by the formula below, which is the same formula for all EPAs. As the base determinants are community based, being the actual fuel costs and the actual plant efficiency (net heat rate), the cost does vary between communities similar to costs noted in Schedule 4.2 Fuel Information.

IPP Energy Price = [Avoided Fuel Costs/Deemed Heat Rate] + [Deferred Maintenance and Capital Costs] – [Additional Costs].

Avoided Fuel Costs: Adjusted annually, effective January 1, in accordance with CPI. The Parties have determined the Avoided Fuel Costs based on the weighted average cost per litre to Buyer of its delivered diesel for the Community for the five-years immediately preceding the Effective Date expressed in **today's** dollars.

Deemed Heat Rate: The Parties[2] have determined the Deemed Heat Rate based on the prior five-year average efficiency rating of Buyer's Generation System. Heat Rate is defined as the total generation in kWh for a given period divided by the fuel in liters used during the same period.

Deferred Maintenance and Capital Costs: Adjusted annually, effective January 1, in accordance with CPI. The Parties have determined the Deferred Maintenance and Capital Costs based on the forecast deferred

[2] In the EPA Agreements, Parties refers to both the Buyer and Seller.

maintenance and capital cost resulting from the displaced diesel generation as a result of this Project.

Additional Costs: Adjusted annually, effective January 1, in accordance with CPI. The Parties have determined the Additional Costs based on the estimated fuel costs to heat the Buyer's diesel plants in the Community, assuming reasonably insulated diesel plants. Upon the request of either Party, "Additional Costs" shall be adjusted after two-years following Buyer's COD to reflect actual fuel costs to heat the Buyer's diesel plants in the Community.

(q) Please refer to the response to (p) above for energy price calculation. No additional items, such as constraint payments, are included in the electricity purchase price. AEY pays only for delivered energy in kWhs as registered by the meter.

It is not possible to forecast the total cost for constraint payments in any given year. The price for energy is known, but the potential inability for the IPP to access the grid is not possible to forecast. As these costs are not in management's control and the magnitude could be significant, AEY has proposed the IPP deferral.

(r) Energy consumed by the IPP is charged at the same rate as their energy export rates.

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

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Undertaking 5:

By B. Rogers to G. Bentivegna
PDF p. 12, lines 21-25 and PDF p. 13, line 1

> G. BENTIVEGNA: Now, focusing on the proposed methodology, can you provide the Alberta Utilities Commission decision number that approved the contribution method that AEY is proposing to align with?
>
> B. ROGERS: I can undertake to provide the relevant decisions from Alberta.

Response:

In Decision 2013-358,[1] the Alberta Utilities Commission (AUC or Commission) directed ATCO Electric Transmission (AET) that the accounting treatment for customer contributions is to be treated in lockstep with capital expenditures.

> 842. For regulatory purposes, a customer contribution is to be accounted for as soon as it is confirmed that a contribution will be required for the project. Waiting until capital expenditures reach ATCO Electric's approved investment level before contributions are received effectively overstates the rate base, and does not recognize the obligation for a customer contribution. This would be especially troublesome if a customer has already paid the contribution up front, ATCO Electric has incurred capital expenditures, and a number of years have passed before the contribution is recorded as a reduction to rate base, especially during this time when the return on CWIP for direct assigned capital projects is included in revenue requirement.

[1] Decision 2013-358, PDF p. 188, para. 842.

Subsequent to that Decision and during a period of significant transmission build in Alberta (generally referred to as the "big build"), the Commission approved a temporary credit relief mechanism called construction work in progress (CWIP) in rate base. Following the approval of that mechanism, AET recorded CWIP and contribution work in progress (KWIP) in rate base.

When the large projects associated with the big build were completed, the Commission directed AET to discontinue CWIP in rate base accounting in Decision 20272-D01-2016:[2]

> 88. ATCO Electric is directed, starting January 1, 2017, to (1) resume normal regulatory AFUDC accounting for direct assigned capital, (2) discontinue CWIP in rate base for direct assigned projects, and (3) discontinue recovering the capital portion of pension costs on a cash basis, and instead return to collection of the capital portion of pension expense as part of invested capital.

As it was not specifically stated in this decision that KWIP should also be removed from rate base, AET continued to record KWIP in rate base until the Commission directed AET in Decision 26573-D01-2023:[3] to account for customer contributions in the same manner as capital expenditures.

> 72. The Commission also requires ATCO Electric to ensure that its current and future accounting practices fully reflect the resumption of normal regulatory AFUDC accounting for its direct assigned capital. Specifically ATCO Electric must account for customer contributions in a manner that ensures that the customer contributions are treated in lockstep with capital expenditures as described in Decision 2013-358 on a go-forward basis.

The aforementioned Decisions have been included as Attachment 1, Attachment 2, and Attachment 3 to this undertaking response, respectively.

2 Decision 20272-D01-2016, PDF p. 301, para. 88.
3 Decision 26573-D01-2023, PDF pp. 19-20, para. 72.

Decision **2013-358**

AUC
Alberta Utilities Commission

ATCO Electric Ltd.

2013-2014 Transmission General Tariff Application

September 24, 2013

The Alberta Utilities Commission
Decision 2013-358: ATCO Electric Ltd.
2013-2014 Transmission General Tariff Application
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Executive summary

This summary is provided for the benefit of the reader. All persons making use of this summary are reminded that the remaining text of the decision should be consulted for all purposes relating to the interpretation and application of the Commission's decisions.

1. In this decision, the Alberta Utilities Commission provides its findings with respect to the application of ATCO Electric Ltd. for approval of its forecast revenue requirements for 2013 and 2014. ATCO Electric Ltd. forecast approximately $1.5 billion in property, plant and equipment additions for 2013 and $2.2 billion for 2014. The forecast capital expenditures were approximately $1.5 billion in 2013 and $1.2 billion for 2014. This forecast included the forecast capital expenditures and capital additions for the Eastern Alberta Transmission Line and the Hanna Regional Transmission Development capital program over the test period.

2. As well, ATCO Electric Ltd. sought approval of its 2011 transmission deferral accounts. The Alberta Utilities Commission approved ATCO Electric Ltd.'s 2011 rate base additions for the non-direct assigned capital projects, subject to any future adjustments that may arise as a result of the true-up of any placeholders.

3. A central theme throughout this proceeding was the impact of the significant forecast capital build on ATCO Electric Ltd.'s forecast revenue requirement. The Alberta Utilities Commission considered and addressed issues raised by participants in the proceeding regarding the testing of forecast capital project costs during the life cycle of the projects, as well as project design and system planning impacts. Consideration of these issues extended the scope of matters examined in this general tariff application. The Alberta Utilities Commission considered that it was necessary to address these issues, to the extent that it was possible to do so in a general tariff application, because of the magnitude of the capital forecast and the level of dissatisfaction expressed by participants regarding the current processes in place for the development, testing and approval of transmission project costs. The Alberta Utilities Commission provided its views on these issues notwithstanding the number of initiatives that are presently ongoing or in development to address the oversight and recovery of transmission capital project costs.

4. The principal areas where the Alberta Utilities Commission was not in agreement with ATCO Electric Ltd. in its application are its request to include a 25 per cent escalation factor for contractors who work on direct assigned capital projects, which the Alberta Utilities Commission denied, and ATCO Electric Ltd.'s forecasts for capital expenditures and capital additions for all direct assigned capital projects, which forecasts were reduced by nine per cent in each of the test years. The Alberta Utilities Commission approved ATCO Electric Ltd.'s forecast labour inflation rate of 3.5 per cent for each of 2013 and 2014, along with its forecast other inflation rate of 2.2 per cent and 2.1 per cent for 2013 and 2014 respectively. In addition, given the forecast $740 million cost for the Hanna Regional Transmission Development capital program, the Alberta Utilities Commission has directed that an audit be carried out with respect to the entire Hanna Regional Transmission Development capital program once the program has been completed and has provided a placeholder for the capital additions for the program, pending completion of the audit.

5. The Alberta Utilities Commission continued to provide credit metric relief for ATCO Electric Ltd. to maintain support for its parent's credit rating and approved several measures to demonstrate its support, including directing the continued use of the federal future income tax method to determine its income tax expense for the test period and directing the continued inclusion of a return on mid-year construction work in progress balances for direct assigned capital projects. The Alberta Utilities Commission also approved a forecast debenture rate of 4.745 per cent.

6. The Alberta Utilities Commission directed ATCO Electric Ltd. to refile its application to reflect the findings in this decision by October 22, 2013. At the time of the refiling, it is expected that the full impact of this decision will be known and final rates for the test period can be set following the Alberta Utilities Commission's assessment of whether the refiling is compliant with this decision.

The Alberta Utilities Commission
Calgary, Alberta

Decision 2013-358
ATCO Electric Ltd. **Application No. 1608610**
2013-2014 Transmission General Tariff Application **Proceeding ID No. 1989**

1 Introduction

1. ATCO Electric Ltd. (ATCO Electric) filed an application with the Alberta Utilities Commission (the AUC or the Commission) on June 29, 2012, requesting various approvals associated with its transmission function for the 2013-2014 test period. Specifically, ATCO Electric applied for approval of:

- Transmission rates to be paid by the Alberta Electric System Operator (AESO) for the use of ATCO Electric's transmission facilities over the test period based on ATCO Electric's forecast revenue requirement. ATCO Electric's applied-for transmission rates are shown on page one of its omissions and updates filing[1] and are summarized below.

	2013	2014
	($million)	
Transmission tariffs	$536.3	$662.7
Increase from existing tariff[2]	$108.3	$234.7
Annual increase	25.3%	23.6%

- The continued use of existing transmission deferral accounts in the test period as well as the following additional or changed deferral accounts:
  - depreciation rates
  - income taxes
  - AESO Rider I credit default risk
  - defined benefit pension costs

- Placeholders relating to ATCO I-Tek rates, the ATCO Utilities corporate costs, pension costs, return on equity and common equity ratio.

- The 2011 transmission deferral accounts and annual filing for adjustments.

[1] The omissions and updates filing is in Exhibit 117.01. The Microsoft Excel version of the revenue requirement schedules that support the omissions and updates filing is in Exhibit 188.02.

[2] This calculation is based on ATCO Electric's approved transmission tariff for 2012 being $428.0 million as reflected in Schedule 3-1 of the application (Exhibit 1, PDF page 64 of 1238, line 19). The transmission tariff for 2012 approved in the Order section of Decision 2011-459 was $429.8 million. The $429.8 million reflected placeholders for return on equity and capital structure. ATCO Electric has reduced the $429.8 million by $1.8 million to reflect the finalization of the placeholder amounts for return on equity and capital structure. The 2012 approved return on equity and capital structure amounts were finalized in Decision 2011-474. ATCO Electric included details of the calculation of the $1.8 million in Schedule 10.0 of Section 32 of the application (Exhibit 1, PDF page 1213 of 1238, line 13).

2. The Commission electronically distributed notice of the application on July 4, 2012, to parties on the Commission's email list for proceedings related to electric utilities. On July 10, 2012, notice of the application was published in the following newspapers: the Edmonton Journal, the Edmonton Sun, the Calgary Herald, and the Calgary Sun.

3. 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 July 24, 2012.

4. The Commission received SIPs from the following parties:

- AESO
- AltaLink Management Ltd.
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- Industrial Power Consumers Association of Alberta (IPCAA)
- Consumers' Coalition of Alberta (CCA)
- Office of the Utilities Consumer Advocate (UCA)
- Alberta Direct Connect Consumers Association (ADC)

5. IPCAA, the CCA, the UCA and the ADC actively participated in the proceeding. The ADC, the CCA, and IPCAA also worked together as members of a coalition they named the Ratepayer Group (RPG). Further details regarding the complete list of registered parties are included in Appendix 1 of this decision.

6. Through a series of letters,[3] the Commission established the following schedule to process the application:

Process step	**Deadline**
Information requests (IRs) to ATCO Electric	August 21, 2012 - 4 p.m.[4]
IR responses from ATCO Electric	September 11, 2012 - 4 p.m.[5]
Submission of signed confidentiality undertakings	October 5, 2012 - 4 p.m.
Non-confidential additional information filed by ATCO Electric	October 10, 2012 - 4 p.m.
Confidential additional information provided by ATCO Electric	October 11, 2012 - 4 p.m.
Non-confidential intervener evidence	October 17, 2012 - 4 p.m.
Unredacted and complete copies of confidential additional material provided by ATCO Electric	October 19, 2012 - 4 p.m.
IRs on non-confidential intervener evidence	October 26, 2012 - 4 p.m.
Confidential intervener evidence	November 2, 2012 - 4 p.m.
IRs on confidential intervener evidence	November 8, 2012 - 4 p.m.
IR responses from interveners on non-confidential intervener evidence	November 9, 2012 - 4 p.m.

[3] Exhibits 36.01, 75.01, 87.01, 96.01, 130.01, 196.01, 215.01, 234.01, 241.01.

[4] Except for IPCAA which was permitted to file its IRs by 4 p.m. on August 24, 2012. Please refer to Exhibit 39.01.

[5] Except for the responses to the IRs of IPCAA. ATCO Electric was permitted to file its responses to the IRs of IPCAA by 4 p.m. on September 14, 2012. Please refer to Exhibit 49.01.

Process step	Deadline
Non-confidential rebuttal evidence	November 19, 2012 - 4 p.m.
IR responses from interveners on confidential intervener evidence	November 21, 2012 - 4 p.m.
Confidential rebuttal evidence	November 28, 2012 - 4 p.m.
Oral Hearing - commencement	December 5, 2012
Oral Hearing - conclusion	January 10, 2013[6]
Submission of additional material from the RPG in accordance with the Commission's ruling made on January 9, 2013	January 14, 2013 - 4 p.m.
Submission of outstanding undertaking response from the RPG to Ms. Wall at Transcript, Volume 8, page 1663	January 14, 2013 - 4 p.m.
Submission of signed confidentiality undertakings	January 16, 2013 - 4 p.m.
Questions on any undertaking responses that were not examined during the oral hearing	January 21, 2013 - 4 p.m.
Questions on additional material submitted by the RPG	January 21, 2013 - 4 p.m.
Responses to questions on additional material submitted by the RPG	January 28, 2013 - 4 p.m.
Responses to questions on undertaking responses	January 28, 2013 - 4 p.m.
Non-confidential written argument	February 11, 2013 - 4 p.m.
Confidential written argument	February 22, 2013 - 4 p.m.
Non-confidential written reply argument	February 26, 2013 - 4 p.m.
Confidential written reply argument	March 14, 2013 - 4 p.m.[7]

7. In addition to the process steps detailed above, the Commission also established process and ruled on motions that had been submitted by the UCA, the ADC and IPCAA regarding the alleged deficiency of the responses that ATCO Electric provided to certain information requests. In the course of addressing these motions and its ruling on them,[8] the Commission granted a request that had been submitted by ATCO Electric for confidential treatment of certain material. In addition, in response to a request submitted by the CCA for advance funding,[9] the Commission issued Decision 2012-273.[10] The Commission considers that the record for the non-confidential portion of the proceeding closed on February 26, 2013. The Commission considers that the record for the confidential portion of the proceeding closed on March 14, 2013.

8. The Commission is a public body and as such, unless otherwise directed, all documents submitted to the Commission as well as the decisions of the Commission are publicly available. As noted above, the Commission granted confidential treatment to a discrete portion of the evidence on the record of this proceeding. This decision reflects the Commission's findings from

[6] The oral hearing consisted of seatings on the following dates: December 5, 2012, December 6, 2012, December 7, 2012, December 10, 2012, December 11, 2012, December 12, 2012, December 13, 2012, January 9, 2013, and January 10, 2013. The oral hearing included a confidential portion. For more details on parties involved in the oral hearing please refer to Appendix 2 of this decision.

[7] This date was set out in an email dated February 25, 2013, from the Application Officer David Mitchell. The email has not been filed on the record of this proceeding.

[8] Exhibit 75.01.

[9] Exhibit 72.01.

[10] Decision 2012-273: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Advance Funding Request from the Consumers' Coalition of Alberta, Application No. 1608879, Proceeding ID No. 2161, October 5, 2012.

all of the evidence on the record of this proceeding, including those issues which were addressed in further detail in the confidential portion of this proceeding.

9. 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 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.

2 Revenue requirements and capital activity summary

10. The following table provides a high level summary of the transmission revenue requirements requested by ATCO Electric for 2013-2014.

Table 1. Major components of the 2013 and 2014 transmission revenue requirements[11]

	2013 ($ million)	Per cent of revenue requirement	2014 ($ million)	Per cent of revenue requirement
Fuel	6.8	1.3%	7.2	1.1%
Operating costs	120.0	22.4%	135.6	20.5%
Depreciation	117.2	21.8%	147.8	22.3%
Return on long-term debt	111.3	20.7%	144.2	21.8%
Return on preferred stock	9.4	1.8%	8.7	1.3%
Return on common stock equity	127.0	23.7%	163.3	24.6%
Income tax expense	48.2	9.0%	59.6	9.0%
Revenue offsets	(3.6)	(0.7)%	(3.7)	(0.6)%
Total	**536.3**	**100.0%**	**662.7**	**100.0%**

11. The following table provides a summary of the forecast capital expenditures and capital additions for the years 2013 and 2014.

Table 2. Forecast capital expenditures and capital additions for the years 2013 and 2014[12]

	2013 ($ million)	2014 ($ million)
Capital expenditures	1,534.7	1,197.6
Capital additions	1,505.4	2,168.9

12. As indicated in the first paragraph of this decision, ATCO Electric's currently applied-for transmission revenue requirements were included in its omissions and updates filing, which was submitted on November 20, 2012. The omissions and updates filing included updates as identified by ATCO Electric in its responses to certain information requests, as well as updates identified by ATCO Electric subsequent to the filing of the initial application. Commission

[11] Exhibit 188.02, schedules 3-1 and 28-1.
[12] Exhibit 188.02, Schedule 10-4.

counsel, during questioning of Mr. McNabb (a witness for ATCO Electric) asked why the omissions and updates filing did not include updates to all of the supporting revenue requirement calculation schedules.[13] Mr. McNabb subsequently undertook to provide, in Microsoft Excel format, a model of the revenue requirement supporting schedules, similar to that provided in Exhibit 3 of the initial application.[14] The response to the undertaking was provided on December 13, 2012.[15]

13. The Commission finds the material included in the revenue requirement supporting schedules in Exhibit 188.02 to be helpful and necessary to assist in validating the accuracy of the revenue requirement calculations. This material should have been provided as part of the omissions and updates filing to support the revised revenue requirements, just as the revenue requirements included in the initial application were supported by the information in Exhibit 3. The Commission directs ATCO Electric, in any future general tariff applications (GTA) where an omissions and updates filing is submitted, to include all detailed supporting revenue requirement schedules, as part of the omissions and updates filing, in Microsoft Excel format with all links and cross references intact.

3 Response to previous Commission directions

14. In the application, ATCO Electric included responses to outstanding Commission directions from Decision 2011-134.[16] The Commission has included a brief summary of ATCO Electric's responses as well as the Commission's findings on each of the responses.

Direction No. 1 (paragraph 25 of Decision 2011-134)

> The Commission is not persuaded by ATCO Electric's explanation that ATCO Electric was compliant with the MFR [minimum filing requirements] because the information was onerous to provide and that it had later provided this information when requested to do so in an information request. Therefore, the Commission finds that ATCO Electric was not initially compliant and unless otherwise directed, ATCO Electric is directed, in tariff filings that require either a depreciation study or a technical update to be filed in support, to fully conform with all requirements as outlined in the MFR.

ATCO Electric's response

15. ATCO Electric submitted that it performed a technical update for depreciation as part of this application and included the technical update in Section 31, Attachment 1 of the application.

Commission findings

16. The requirements relating to depreciation studies and technical updates included in the MFR document are listed in paragraph 22 of Decision 2011-134. Because ATCO Electric filed a technical update as part of the current application, only the following areas of the MFR are applicable:

> As part of the minimum filing requirements, irrespective of whether the utility is filing a

[13] Transcript, Volume 2, pages 420-422.
[14] Transcript, Volume 3, page 447.
[15] Exhibits 188.01 and 188.02.
[16] Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.

> new depreciation study or a technical update, the utility is required to file:
> • current-year plant balances by account/sub-account and vintage, if required to do the depreciation calculation; and
> • all calculations showing the development of the depreciation rate, depreciation reserve adjustment, and resulting depreciation expense requested by the utility.[17]

17. The Commission's review of the information provided by ATCO Electric in the application, specifically Attachment 1 of Section 31, Section 6 and Section 25, demonstrates that ATCO Electric has provided the information required under the MFR. Consequently, ATCO Electric has complied with the direction included in paragraph 25 of Decision 2011-134. The Commission reminds ATCO Electric that the direction included in paragraph 25 of Decision 2011-134 has no end date so ATCO Electric is still bound by this direction with respect to future GTAs.

Direction No. 2 (paragraph 33 of Decision 2011-134)

> The Commission tests the forecasts presented in any cost of service tariff application through, amongst other things, investigating trend information. Unless otherwise directed, the Commission directs ATCO Electric in all future tariff applications to file applied for, actual, and approved amounts for the years 2003 through to and including its test years as part of its application.

ATCO Electric's response

18. ATCO Electric referred to the supplementary schedules provided in Attachment 5 of Section 31 of the application.

Commission findings

19. The Commission finds the information provided by ATCO Electric in Attachment 5 of Section 31 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 33 of Decision 2011-134. The Commission directs ATCO Electric, in its next GTA, to file applied-for, actual and approved amounts for the years 2005 through to and including the relevant test years as part of the application.

Direction No. 5 (paragraph 149 of Decision 2011-134)

> The Commission is not persuaded to disallow the amounts forecast for EARA payments from ATCO Electric's revenue requirement during the test years as requested by the CCA. However, the Commission cannot provide any assurance of future recovery to ATCO Electric in respect of its proposed EARA payments. The Commission agrees with the UCA that ATCO Electric must bear the obligation to demonstrate the prudence of EARA expenditures at the time of final prudence review of the transmission projects' actual expenditures as part of the direct assigned deferral account reconciliation process. Therefore, the Commission directs ATCO Electric, in all future tariff applications, to submit a separate schedule which clearly shows proposed EARA payments on a project by project basis.

ATCO Electric's response

20. ATCO Electric included a separate schedule detailing the forecast Early Access and Resolution Agreement (EARA) payments on a project by project basis in Attachment 3 of

[17] Decision 2011-134, paragraph 22.

Section 2 of the application. ATCO Electric provided additional information in response to information requests ADC-AE-050[18] and CCA-AE-014.[19] There was also discussion involving the EARA payments during the oral hearing.[20]

Commission findings

21. The Commission finds that the information provided by ATCO Electric in Attachment 3 of Section 2 of the application, and the additional information as described in the previous paragraph, demonstrates that ATCO Electric has complied with the direction included in paragraph 149 of Decision 2011-134. The Commission reminds ATCO Electric that the direction included in paragraph 149 of Decision 2011-134 has no end date so ATCO Electric is still bound by this direction with respect to future applications.

Direction No. 15 (paragraph 343 of Decision 2011-134)

> In addition, the Commission finds that given the magnitude of program management costs for ATCO Electric's distribution and transmission functions (approximately $3 million in each of 2011 and 2012), a further breakdown of these costs is needed. At the same time, the Commission considers that identifying costs to the most detailed level as suggested by the CCA is not economic. In light of the above, the Commission directs ATCO Electric in future tariff applications to provide a further breakdown of its program management costs as follows:
>
> - contractor consenting
> - internal consenting
> - other internal (including program planning, safety, patrolling, quality inspection, and negotiation with suppliers)

ATCO Electric's response

22. ATCO Electric included a separate schedule detailing the forecast vegetation management costs, in Attachment 2 of Section 5 of the application.

Commission findings

23. The Commission finds that the information provided by ATCO Electric in Attachment 2 of Section 5 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 343 of Decision 2011-134. The Commission directs ATCO Electric to update the information in Attachment 2 of Section 5, if necessary, to reflect the final forecast amounts for 2013 and 2014 that are included in the compliance filing. The Commission reminds ATCO Electric that the direction included in paragraph 343 of Decision 2011-134 has no end date so ATCO Electric is still bound by this direction with respect to future applications.

4 Terms and conditions of service

24. As part of the application, ATCO Electric filed a copy of the terms and conditions of service under which it operates[21] and indicated that these terms and conditions of service were

[18] Exhibit 52.01.
[19] Exhibit 53.01.
[20] Transcript, Volume 4, pages 686-691.
[21] Exhibit 1, application, Section 3, Attachment 1.

approved in Decision 2010-116,[22] that no issues were raised in the proceeding with respect to them and that they should continue. In response to information request UCA-AE-016[23] ATCO Electric confirmed that the terms and conditions of service filed in Attachment 1 of Section 3 of the application were identical to the ones approved in Decision 2010-116.

Commission findings

25. In paragraph 19 of Decision 2010-116 the Commission stated:

> 19. In consideration of AE and EPC's participation in the development of the TFO T&Cs and its awareness and participation in the subsequent Commission approval processes thereto and as neither of these parties filed a SIP in this proceeding, the Commission confirms that the final T&Cs filed by AltaLink for the Second Refiling will apply to AE and EPC.

26. In the application, ATCO Electric requested placeholder treatment for its terms and conditions of service. During the oral hearing, Commission counsel questioned ATCO Electric on why it had requested placeholder treatment for the terms and conditions of service,[24] as evidenced by line 20 of Attachment 3 of Section 1 of the application. In an undertaking response,[25] ATCO Electric clarified that it was not seeking placeholder status for its terms and conditions of service as part of this application, and that it would remove the reference from Attachment 3 of Section 1 of the application in the compliance filing. The Commission therefore directs ATCO Electric, as part of the compliance filing, to file an updated Attachment 3 from Section 1 of the application, in which any reference to a placeholder for its terms and conditions of service is excluded.

27. Based on the assurance from ATCO Electric that the terms and conditions of service included in Attachment 1 of Section 3 of the application are the same as those approved in Decision 2010-116, and recognizing that no parties raised any objections to continuing with these, the Commission approves the continuation of the terms and conditions of service as filed in Attachment 1 of Section 3 of the application, subject to the removal of any reference to placeholder treatment as directed above.

5 General areas

5.1 Necessity of deferral accounts

28. In its application, ATCO Electric requested approval to continue a number of previously-approved deferral accounts, establish additional ones and make a change to another. It stated that the requested deferral accounts continued to meet the previously-accepted criteria for the establishment of such accounts, which ATCO Electric identified as follows:

- not under the control of the company and not reasonably able to be forecast or
- a variance in forecasting could produce a loss or gain of substantial magnitude

[22] Decision 2010-116: AltaLink Management Ltd., Refiling of Transmission Facility Owner Terms and Conditions Pursuant to Decision 2009-248, Application 1605866, Proceeding ID. 474, March 18, 2010.
[23] Exhibit 51.01.
[24] Transcript, Volume 3, pages 540-541.
[25] Exhibit 147.01.

29. The previously-approved deferral accounts that ATCO Electric requested approval to continue during the 2013-2014 test period are as follows:

- isolated generation fuel costs
- right-of-way payments
- property taxes
- direct assigned capital projects
- variable pay program (VPP)

30. ATCO Electric also requested approval to establish the following new deferral accounts:

- depreciation rates
- AESO Rider I credit default risk
- defined benefit pension costs

31. ATCO Electric requested that changes be made to the following deferral account:

- income taxes

32. Finally, similar to previous years, ATCO Electric requested the continuation of the ability to flow through (dollar for dollar) to the transmission tariff:

- costs relating to the transmission function during the 2013-2014 test period which result from subsequent amendments to the *Electric Utilities Act,* S.A. 2003, c. E-5.1, Section 1(1)(f.1) and the regulations thereunder
- costs which arise as a consequence of the Commission approved tariffs for 2013 and 2014 with respect to ATCO Electric or any other industry participant including the AESO

33. During the course of the proceeding, the possibility of establishing additional deferral accounts was raised by interveners (for operation and maintenance (O&M) labour) and by the Commission (for debenture rates and for preferred share rates). Additionally, parties also tested the impacts of eliminating all of the requested deferral accounts. In response to information request CCA-AE-006(c),[26] ATCO Electric provided an assessment of the risks and benefits of terminating all of the deferral accounts for which it had requested approval.

5.1.1 Isolated generation fuel costs

34. ATCO Electric is responsible for operating and maintaining a number of natural gas and diesel fueled generating plants throughout northern and central Alberta, as well as one hydroelectric plant. Each of these generating plants serves as the sole source of electrical supply to the respective communities, telecommunications sites or industrial customers and are not part of the Alberta interconnected electric system. These generating plants are therefore referred to as

[26] Exhibit 53.01.

"isolated." The forecast natural gas and diesel fuel costs associated with running these isolated generation units is dependent upon a number of factors, including the price of natural gas and diesel fuel, as well as the volume of generation required to serve customer load in these isolated areas. In the omissions and updates filing, ATCO Electric included forecast isolated generation fuel cost amounts of $6.8 million for 2013 and $7.2 million for 2014.[27]

35. ATCO Electric stated that given the potential variability in the fuel costs for isolated generation due to either fuel price and/or volume, it was requesting continuation of the deferral account for these costs. Any difference between the 2013 and 2014 forecast approved fuel costs and the actual fuel costs for these years would be trued-up annually. ATCO Electric added that the balance in the deferral account will be calculated monthly and requested that carrying costs be awarded and calculated in accordance with the AUC's Rule 023: *Rules Respecting Payment of Interest* (Rule 023).

36. The CCA agreed that this deferral account should be continued and submitted that without the deferral account customers would have paid approximately $1.8 million more in each of the five years from 2007 to 2011 because the actual fuel costs for these years were less than the forecast approved costs. The CCA stated that given the considerable uncertainty in the forecast of fuel prices and heat rates, and given that these factors are not within the control of ATCO Electric, material variances may result from differences between the actual results and the forecast approved factors.[28]

37. The ADC proposed that over-forecasting may have led to the balances in the deferral account for the years 2007 to 2012 and supported the elimination of the fuel deferral account if the fuel forecast is reduced to $6.3 million in each of 2013 and 2014.

Commission findings

38. The fuel forecast included by ATCO Electric in the omissions and updates filing was $6.8 million for 2013 and $7.2 million for 2014. The forecast revenue requirements included in the omissions and updates filing are $536.3 million for 2013 and $662.7 million for 2014. This results in the forecast fuel costs for 2013 representing approximately 1.3 per cent of the total forecast revenue requirement and in 2014 the corresponding figure is approximately 1.1 per cent. The Commission considers that these percentages are not significant.

39. The Commission also considers that there is no incentive for ATCO Electric to manage the level of these costs if they are afforded deferral treatment. The fuel efficiency of the isolated generating units may be improved if ATCO Electric can benefit from efficiencies but with a deferral account there is no incentive to seek out any efficiencies.

40. The Commission agrees that natural gas and diesel prices fluctuate and are not under the control of ATCO Electric, however the Commission also recognizes that there are a number of other cost items included in this application over which ATCO has no control, such as debenture rates, for which ATCO Electric is willing to accept the forecast risk.

[27] Exhibit 117.02, page 1 of 2, line 7; page 2 of 2, line 7.
[28] Exhibit 235.01, argument of the CCA, paragraphs 7-8.

41. The Commission agrees with the ADC that if forecast fuel costs had been more accurate, the resulting balances in the deferral account may have been smaller. With a deferral account, little attention is paid to the fuel forecast.

42. Using the historical information provided in Section 31 of the application, the Commission has prepared the following analysis.

Table 3. Forecasting accuracy from 2007-2012 with respect to fuel costs[29]

	2009	2010	2011	2012	4 year average
	($ million)				
Actual costs	6.2	6.3	6.0	6.3	6.2
Approved costs	9.3	9.6	8.3	8.8	9.0
Difference in dollars	(3.1)	(3.3)	(2.3)	(2.5)	(2.8)
Difference in percentage	(33.3)%	(34.4)%	(27.7)%	(28.4)%	(31.1)%

43. The information in Table 3 demonstrates that ATCO Electric's actual fuel costs over the four years from 2009 to 2012 have all been lower than the approved forecast. Using the four-year average variance of approximately 31 per cent and applying it to the 2013 forecast fuel cost of $6.8 million included in the omissions and updates filing would result in a reduction to the fuel costs of approximately $2.1 million, leaving the expected fuel costs for 2013 at $4.7 million. The same calculation applied to the 2014 forecast fuel costs of $7.2 million would result in expected fuel costs of $5.0 million for 2014.[30] In Section 6 of this decision, the Commission has approved the fuel forecast costs for 2013 and 2014 at $6.3 million for each year. This amount is $1.6 million greater than the expected $4.7 million for 2013 arrived at using ATCO Electric's four-year average forecasting variance and $1.3 million greater than the expected $5.0 million for 2014. The Commission considers that the forecast fuel amounts approved in Section 6 of this decision allows ATCO Electric some room for forecast error and that the amount of the error would not be material. Based on the Commission's considerations and analysis of fuel costs, the Commission finds that a deferral account is not warranted for fuel costs and consequently rejects ATCO Electric's request for a deferral account for isolated generation fuel costs. Because it has been determined that the deferral account for isolated generation fuel costs should be discontinued, it is not necessary to make any determination regarding the awarding of interest costs as requested pursuant to AUC Rule 023.

5.1.2 Right-of-way payments

44. Right-of-way payments, also referred to by ATCO Electric as annual structure payments, are included in Schedule 5-1 of ATCO Electric's revenue requirement supporting schedules entitled "Schedule of Transmission Operation & Maintenance Costs By Account." In the omissions and updates filing, ATCO Electric included forecast annual structure payment amounts of $4.0 million for 2013 and $4.4 million for 2014.[31]

45. ATCO Electric stated that it is legislated by the *Surface Rights Act*, RSA 2000, c. S-24, to pay annual compensation to agricultural landowners or occupants for transmission structures that

[29] Exhibit 1, application, Section 31, Attachment 5, Schedule 3-3, pages 2 and 3 of 174.
[30] $7.2 million multiplied by (1 - 31 per cent) equals $5.0 million.
[31] Exhibit 117.16.

ATCO Electric has on their property and that each year it issues approximately 5,500 compensation payments to landowners. ATCO Electric indicated that these payment amounts are impacted by decisions from the Surface Rights Board, and that because of recent Surface Rights Board decisions, ATCO Electric increased its forecast annual structure payments as reflected in the omissions and updates filing.

46. ATCO Electric submitted that it anticipates a continuation of significant marketplace uncertainty throughout 2013 and 2014 as annual compensation associated with new transmission structures (240-kilovolts (kV) and 500-kV) on several large transmission projects is determined and pressure to increase annual compensation for existing structures continues. Given this uncertainty, ATCO Electric requested that the deferral account for right-of-way payments remain in place for 2013 and 2014.

47. No issues regarding this requested deferral account were raised by any of the parties during the proceeding.

Commission findings

48. The right-of-way payments included by ATCO Electric in the omissions and updates filing were $4.0 million for 2013 and $4.4 million for 2014. The forecast revenue requirements included in the omissions and updates filing are $536.3 million for 2013 and $662.7 million for 2014. This results in the forecast right-of-way payments for 2013 and 2014 representing approximately 0.7 per cent of the total forecast revenue requirements for each of these years. The Commission considers that these percentages are not significant.

49. The Commission agrees that these payments are impacted by decisions made by the Surface Rights Board, and that such decisions are not under the control of ATCO Electric. Based on the information included in Table 4 below, it is clear that, for every year from 2007 to 2011 ATCO Electric has had an amount owing to the AESO for the balance in the right-of-way payments deferral account. The Commission considers that if the forecast right-of-way payments for these years had been more accurate, the resulting balance in the deferral account would have been smaller. With a deferral account, little attention is paid to the forecast.

50. Using the historical information provided in Section 31 of the application, the Commission has prepared the following analysis:

Table 4. Forecasting accuracy from 2007-2011 with respect to right-of-way payments[32]

	2007	2008	2009	2010	2011	5-year average
	($ million)					
Actual costs	1.4	1.8	1.9	1.9	2.6	1.9
Approved costs	2.9	3.9	3.2	3.8	3.1	3.4
Difference in dollars	(1.5)	(2.1)	(1.3)	(1.9)	(0.5)	(1.5)
Difference in percentage	(51.7)%	(53.8)%	(40.6)%	(50.0)%	(16.1)%	(44.1)%

51. As evidenced from the information in Table 4, ATCO Electric's actual right-of-way payments over the five years from 2007 to 2011 have all been lower than the approved forecast.

[32] Exhibit 1, application, Section 31, Attachment 5, Schedule 5-1, pages 8 and 9 of 174.

Using the five-year average variance of approximately 44 per cent and applying it to the 2013 forecast right-of-way payments of $4.0 million included in the omissions and updates filing would result in a reduction to the right-of-way payments of approximately $1.8 million, leaving the expected actual right-of-way payments for 2013 at $2.2 million. The same calculation applied to the 2014 forecast right-of-way payments of $4.4 million would result in the expected actual right-of-way payments for 2014 being $2.5 million.[33]

52. Pursuant to Section 46(2) of the *Transmission Regulation*, AR 86/2007, the Commission must consider payments that are included in a TFO's tariff that are made by a TFO to a landowner, pursuant to any agreement between the TFO and the landowner, to be prudent unless an interested person satisfies the Commission that the payments are unreasonable.

53. The Commission considers that given the historical forecasting accuracy of ATCO Electric with respect to right-of-way payments, as demonstrated in Table 4 above, and the restrictions imposed by Section 46(2) of the *Transmission Regulation*, it is necessary to protect both customers and ATCO Electric against the possibility that the 2013 and 2014 forecast amounts are also not accurate. Therefore, the Commission finds that the only choice available is to approve the deferral account for right-of-way payments as applied for and such approval is hereby granted.

5.1.3 Property taxes

54. Property taxes, also referred to by ATCO Electric as taxes other than income taxes, are included in Schedule 5-1 of ATCO Electric's revenue requirement supporting schedules, entitled "Schedule of Transmission Operation & Maintenance Costs By Account." In addition, more detail is provided in Schedule 5-6 of the revenue requirement supporting schedules. In the initial application and the revenue requirement supporting schedules for the omissions and updates filing,[34] ATCO Electric included forecast annual property taxes amounts of $30.0 million for 2013 and $37.5 million for 2014.

55. ATCO Electric indicated that the forecast of taxes other than income taxes for 2013 and 2014 include inflation factors on both the assessment year modifier and the mill rate. ATCO Electric added that the assessment year modifier is used to calculate the assessed values of the property while the mill rate is applied to the assessed values to determine the amount of property taxes. It stated that given the significant variability in the assessment year modifier over recent years, the variability in the capital additions forecast for 2013 and 2014, and that mill rates set by the various municipalities are beyond the control of ATCO Electric, the deferral account for property taxes should continue for 2013 and 2014.

56. No issues regarding this requested deferral account were raised by any party during the proceeding.

Commission findings

57. The property taxes included by ATCO Electric in the omissions and updates filing were $30.0 million for 2013 and $37.5 million for 2014. The forecast revenue requirements included in the omissions and updates filing are $536.3 million for 2013 and $662.7 million for 2014. This results in the forecast property taxes for 2013 representing approximately 5.6 per cent of the total

[33] $4.4 million multiplied by (1 - 44 per cent) equals $2.5 million.
[34] The revenue requirement supporting schedules for the omissions and updates filing are in Exhibit 188.02.

forecast revenue requirement and in 2014, the corresponding figure is approximately 5.7 per cent. The Commission considers that these percentages are significant.

58. The Commission agrees with ATCO Electric that there continues to be a need for this deferral account because of the magnitude of risk associated with the variability between forecast and actual property taxes due to significant capital additions and property tax related indices. For these reasons, the Commission approves the property tax deferral account as requested.

5.1.4 Direct assigned capital projects

59. Direct assigned capital projects are capital projects that are directly assigned to ATCO Electric by the AESO. The process involving direct assigned capital projects is explained in more detail in Section 11.1 of this decision. In Schedule 10-4 of the revenue requirement supporting schedules for the omissions and updates filing,[35] ATCO Electric included forecast direct assigned capital projects additions of $1.4 billion for 2013 and $2 billion for 2014.

60. Consistent with previous treatment of direct assigned capital projects deferral accounts, ATCO Electric proposed a deferral account for direct assigned capital projects additions, direct assigned capital projects work in progress and direct assigned capital projects contributions. The deferral would account for the revenue requirement impact (return, depreciation, and income tax components) associated with the differences between the actual and forecast approved direct assigned capital projects additions, direct assigned capital projects work in progress and direct assigned capital projects contributions. Details of the calculation related to the balance in the 2011 direct assigned capital projects deferral account are included in Schedule 2.0 of Section 32 of the application.[36] ATCO Electric added that carrying costs will be calculated in accordance with the AUC's Rule 023.

61. ATCO Electric requested that this deferral account be approved for 2013 and 2014 and submitted that the forecasting and business risks associated with direct assigned capital projects are very high given the process involved in receiving approvals for these projects as well as the magnitude and variability of the dollar amounts involved.

Commission findings

62. The Commission agrees that there continues to be a need for this deferral account because the exposure and magnitude of risk associated with the variability between forecast and actual costs and timing of direct assigned capital projects remains. The forecast for direct assigned capital projects additions for 2013 and 2014, being well in excess of $1.0 billion each year, is clearly material and even small variances with respect to this forecast can result in significant differences to the net earnings of ATCO Electric. In addition, this deferral account also accounts for variances between the forecast and actual construction work in progress (CWIP) balances for direct assigned capital projects. For these reasons, the Commission approves the direct assigned capital projects deferral account and the methodology for its determination.

[35] Exhibit 188.02.
[36] Exhibit 1, application, PDF page 1202 of 1238.

5.1.5 Variable pay program

63. ATCO Electric indicated in its application that it introduced a VPP for its senior managers in 2006 as part of the company's total compensation package and that since that time it has taken a measured growth approach to expanding the VPP based on market requirements. More details regarding the VPP are included in Section 18.1 of this decision.

64. ATCO Electric described the past practice up to and including 2012 where all of the VPP payment amounts were expensed and included in the calculation of the deferral account balance, and proposed that this practice be changed for the 2013-2014 test period. It indicated that for any VPP eligible employees who work predominantly on direct assigned capital projects, the VPP would be capitalized as part of the cost of the direct assigned capital projects. As a result, any difference between the VPP amounts approved for these employees and the actual amounts would be included as part of the calculation of the direct assigned capital projects deferral account. ATCO Electric stated that this change is proposed to recognize that VPP payouts to employees working directly on direct assigned capital projects are more appropriately included and reflective of the cost of the projects themselves. VPP amounts for the remaining eligible employees will be treated as they were in the past, in that they will be expensed and included in the calculation of the VPP deferral account balance.

65. In the response to information request ADC-AE-097(c),[37] ATCO Electric indicated that its forecast total VPP payments for the 2013 and 2014 test period are based on 90 per cent of the out-of-scope (or non-union) employees in the organization being eligible for VPP. It stated that the eligibility rate was approximately 70 per cent in 2011 and forecasted to be approximately 90 per cent in 2012. Schedule 25-11 of the application includes more details about the total VPP amounts included in the forecast for the 2013 and 2014 test period, and line 21 of that schedule includes forecast VPP amounts to be expensed of $1.6 million in 2013 and $1.8 million in 2014. These amounts would be subject to the VPP deferral account as proposed by ATCO Electric. It clarified that consistent with past practice, the VPP deferral account would refund to or collect from the AESO, the difference between what is forecast in the application for VPP and what is actually paid out in 2013 and 2014 for the VPP.

66. ATCO Electric submitted that the VPP is based on market requirements that continue to evolve and as such, a continuation of the deferral account was being requested. During the oral hearing, Commission counsel questioned ATCO Electric witnesses about whether or not ATCO Electric still wanted the deferral account for VPP.[38] In response, and as reiterated in its written argument,[39] ATCO Electric indicated that as long as the Commission approved the 90 per cent eligibility for 2013 and 2014, it would be comfortable without the deferral account. ATCO Electric stated that if the 90 per cent eligibility is not granted, a continuation of the deferral account will be required.[40]

Commission findings

67. There are two issues that need to be addressed in this area. The first of these issues is whether ATCO Electric's accounting practice with respect to the VPP amounts forecast for VPP eligible employees who work predominantly on direct assigned capital projects should be

[37] Exhibit 52.01.
[38] Transcript, Volume 3, pages 494-496.
[39] Exhibit 239.01, ATCO Electric argument, paragraph 24.
[40] Exhibit 239.01, ATCO Electric argument, paragraph 24.

changed. The Commission agrees with ATCO Electric that VPP payouts to employees working directly on direct assigned capital projects are more appropriately included in the cost of these projects. This practice aligns with accepted accounting practice as well and therefore, the Commission approves the request made by ATCO Electric in this regard. As a result of this change, any differences between the approved and actual VPP amounts for these employees during the 2013 and 2014 test period will be captured and reflected in the calculation of the direct assigned capital projects deferral account.

68. The Commission also finds that VPP payouts for employees who work on non-direct assigned capital projects should also be charged to the capital projects they work on. As a result, the Commission directs ATCO Electric, in the compliance filing, to include forecast VPP amounts for 2013 and 2014 for employees who work predominantly on non-direct assigned capital projects, as part of the forecast capital expenditures for these projects; and to remove these amounts from whatever expense category they were included under in the application.

69. The second issue to be decided is whether to continue deferral treatment for the O&M component of the VPP, and the non-direct assigned capital projects component. The VPP amounts to be expensed were included by ATCO Electric in the omissions and updates filing as $1.6 million for 2013 and $1.8 million for 2014. The forecast revenue requirements included in the omissions and updates filing are $536.3 million for 2013 and $662.7 million for 2014. This results in the forecast VPP amounts to be expensed for 2013 and 2014 representing approximately 0.3 per cent of the total forecast revenue requirements for these years. The Commission considers that these percentages are not significant.

70. The Commission is not persuaded by ATCO Electric's argument that the VPP is based on market requirements that continue to evolve and as such a continuation of the deferral is required. The Commission also considers that, in this case, the eligibility percentage has no bearing on whether or not a deferral account is required. The forecast VPP amounts included in the application are based on 90 per cent eligibility, and as explained in the previous paragraph of this decision, the O&M category for these amounts is not a significant component of the revenue requirements being requested for 2013 and 2014. Whether the Commission approves a 90 per cent eligibility or a 50 per cent eligibility, the resulting amount of VPP related to O&M is not material.

71. The issue of symmetry with respect to the establishment of deferral accounts is a relevant factor in this discussion. The symmetry factor was referred to by the Commission in paragraph 73 of Decision 2010-189[41] as follows:

> 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

[41] Decision 2010-189: ATCO UTILITIES, Pension Common Matters, Application No. 1605254, Proceeding ID No. 226, April 30, 2010.

> and fair manner in both test years and non-test years." This will be referred to as the symmetry factor. (footnotes omitted)

72. One of the reasons why the VPP deferral account was initially established was because the regulator was concerned that as it was a new program, that in the absence of a deferral account, the utility might be incented to not pay to employees all of the VPP amounts included in the approved revenue requirement and instead, keep some of these revenues. Such protection is no longer required because ATCO Electric has established a history of paying the VPP amounts. In addition, there will be pressure from employees for ATCO Electric to continue to pay these VPP amounts, and the Commission and interveners will undoubtedly compare the actual amount of VPP payments made by ATCO Electric in 2013 and 2014 to the forecast approved amounts, as part of ATCO Electric's next transmission GTA.

73. Unlike a lot of other areas for which ATCO Electric requested deferral treatment, the decision whether or not to pay out the VPP is entirely under the control of ATCO Electric. For all of these reasons, deferral treatment for the O&M component of the VPP shall be discontinued, and deferral treatment will not be granted for the non-direct assigned capital projects component either.

5.1.6 Depreciation rates

74. ATCO Electric stated that under the International Financial Reporting Standards (IFRS), it has a requirement to review its depreciation rates annually and implement new depreciation rates if necessary.[42] ATCO Electric indicated that because it filed a full depreciation study in its 2011-2012 GTA, it only filed a technical update to its depreciation rates in the current application. ATCO Electric requested the ability to file future applications to reflect changes in its depreciation rates due to the IFRS requirement and proposed to flow any impact of depreciation rate changes through to customers within the 2013-2014 test period. It stated that the effect of any change in depreciation rates would be determined using the approved forecast rate base for the 2013-2014 test period and would also be incorporated into the calculation of the direct assigned capital projects deferral account.

75. ATCO Electric stated that the need for deferral account treatment for depreciation rates is to account for new information or events that occur in a year where it has not undertaken a full depreciation study. It added that this will permit it to harmonize, to the extent possible, IFRS and regulatory accounting, and to avoid the administrative burden of keeping two sets of financial records. ATCO Electric advised that its distribution function has included a Y factor flow through of the effect of changes to depreciation rates for the distribution assets in the performance-based regulation (PBR) plan. In addition, it submitted that its transmission and distribution functions make use of certain common assets, the costs of which are allocated between them. ATCO Electric stated that it would not make sense from an accounting or regulatory aspect to have different depreciation rates in place for these common assets in the event the Commission approves a change in depreciation rates for one of the functions, but not the other.

[42] In response to information request ADC-AE-068 (Exhibit 52.01), ATCO Electric provided the applicable International Accounting Standard.

Discussion of the issue

76. The CCA addressed the deferral account related to depreciation rates in tandem with its submission that the IFRS deferral account approved in Decision 2011-134 be continued, something for which ATCO Electric did not request approval. The CCA's requested continuation of the IFRS deferral account is addressed in Section 5.3.1 of this decision.

77. The CCA argued that ATCO Electric's proposal with respect to requesting the ability to change depreciation rates for ratemaking purposes between GTAs, to match IFRS depreciation rates, should be rejected by the Commission because any such changes for ratemaking requirements could be given effect when ATCO Electric files its subsequent GTAs. The CCA maintained that there has always been the potential for differences between regulatory reporting and external financial reporting that do not automatically need to be mirrored.

78. Alternatively, the CCA made a secondary recommendation that, if its request to continue the IFRS deferral account is approved by the Commission, it would not be opposed to the depreciation rates deferral proposed by ATCO Electric.

Commission findings

79. The Commission observes that ATCO Electric has largely adopted regulatory depreciation practices for the purposes of IFRS with the exception of those matters for which there are specific treatments required under IFRS (for example, the treatment of gains and losses and net salvage).

80. Given that the derivation of the depreciation rates in question appears to have remained much the same since the implementation of IFRS, it is unclear to the Commission where ATCO Electric expects material differences to arise, such that deferral treatment is required.

81. As discussed in Section 8 of this decision, the Commission acknowledges that the amortization of accumulated depreciation variance included in 2013 and 2014, is the same as that approved in Decision 2011-134, which was last calculated by ATCO Electric using data as of December 31, 2008. The Commission views this as evidence that the magnitude of changes due to either depreciation parameters, or the composition of plant balances that might have an impact on the depreciation variance, has been or is expected to continue to be minimal, given that ATCO Electric continued to be satisfied with these amounts and did not seek Commission approval in its last depreciation study, for an update to its annual provision for true-up related to the accumulated depreciation variance as calculated at December 31, 2008.

82. Furthermore, during the oral hearing, an ATCO Electric witness stated that the company would be relying on discussions "with the appropriate engineers and management to determine if there are events occurring or expected to occur with a high probability that will cause ATCO Electric to view that the AUC's previously approved depreciation parameters are inadequate."[43] While the Commission agrees that these discussions are an important source of information used in the determination of depreciation rates, the Commission is concerned that the period of time over which such observations would be made by ATCO Electric staff likely exceeds the time frame for which ATCO Electric requests the ability to determine that a change in rates is warranted and could realistically be incorporated. Based on the issue date of this decision, and the requirement for ATCO Electric to submit a compliance filing, which will involve more time,

[43] Transcript, Volume 3, page 454, lines 2-6.

the Commission also considers that there is not much time remaining in the 2013-2014 test period during which possible depreciation rate changes could be identified, applied for, approved and implemented.

83. For these reasons, the Commission denies the request for deferral treatment for depreciation rates.

5.1.7 AESO Rider I credit default risk

84. ATCO Electric requested that the Commission approve an AESO Rider I credit default risk deferral account to address stranded assets that might arise as a result of an AESO Rider I customer defaulting on its obligations without having sufficient financial security to discharge those obligations. In response to information request AUC-AE-003(a),[44] ATCO Electric confirmed that it had not incorporated the approval of Rider I in preparing the current application.

85. ATCO Electric indicated that in Decision 2011-474,[45] the Commission approved Rider I in principle and directed the AESO to file a separate Rider I tariff application which would allow alternative treatment with respect to the up-front payment of construction contributions for system access service connections for industrial customers. Rider I would allow customers to pay the construction contribution principal in equal monthly amounts, over a period of up to 20 years, plus a carrying cost on the unpaid contribution balance. Rider I would also allow for contributions that were previously paid for transmission facilities to be refunded and subsequently repaid through the rider.

86. ATCO Electric explained that, at paragraphs 542 and 545 of Decision 2011-474, the issue of credit default by a Rider I customer was addressed, which reiterated that utilities bear the risk for any stranded assets, including those assets which are being paid for under Rider I. ATCO Electric stated that the AESO Rider I application was not approved in Decision 2012-364,[46] but the Commission indicated in that decision that, once the stranded asset issue is resolved, the AESO may reapply for its proposed Rider I as part of a future tariff application. ATCO Electric submitted that it therefore considers that utilities still face an AESO Rider I credit default risk and added that the associated impact of the risk of an asset becoming stranded is not under the control of ATCO Electric; it cannot reasonably be forecast, and could be material. Hence a deferral account is required. In response to information request UCA-AE-055(b),[47] ATCO Electric confirmed that the proposed deferral account will only include the costs of Rider I payments in default and provided more information about the operation of this proposed deferral account in response to information request IPCAA-AE-054.[48]

Commission findings

87. The issue of who bears the risk with regard to stranded assets is currently being examined by the Commission in the course of Proceeding ID No. 20, the Utility Asset Disposition proceeding. The Commission considers that, if it determines in Proceeding ID No. 20 that

[44] Exhibit 50.01.
[45] Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011.
[46] Decision 2012-364: Alberta Electric System Operator, 2012 Amortized Construction Contribution Rider I, Application No. 1608602, Proceeding ID No. 1982, December 28, 2012.
[47] Exhibit 51.01.
[48] Exhibit 54.01.

utilities bear the risk with respect to stranded assets, there is no requirement for a deferral account for AESO Rider I credit default risk because ATCO Electric will bear the risk for any AESO Rider I credit defaults. Conversely, if the Commission determines in Proceeding ID No. 20 that customers bear the risk with respect to stranded assets, ATCO Electric would be able to bring forward an application for the recovery of these costs, if and when, such costs arise.

88. ATCO Electric has not included any such AESO Rider I credit defaults in the 2013 revenue requirement or the 2014 revenue requirement and there has been no associated placeholder amount identified in revenue requirements over the test period. It is therefore unnecessary to establish a deferral account during this test period. The Commission therefore denies ATCO Electric's request to establish a deferral account for AESO Rider I credit default risk. The Commission directs ATCO Electric, in the compliance filing, as part of the updated Section 1, Attachment 3 schedule to be submitted, to remove the AESO Rider I credit risk deferral.

5.1.8 Income taxes

89. ATCO Electric requested a change in its income taxes deferral account that previously included rates, income tax deductible capital costs and deductions of deferrals for income tax purposes. As explained in sections 7 and 28 of its application, ATCO Electric has requested, as part of the 2013-2014 revenue requirements, recovery of provincial future income taxes (FIT), previously-approved federal FIT, and direct assigned capital projects CWIP, in order to establish its credit metrics at a level necessary to maintain an "A" credit rating.

90. ATCO Electric explained that if recovery of provincial and federal FIT is approved by the Commission, all timing differences between current income taxes and FIT are eliminated, and the need for a deferral on income tax deductible capital costs and deductions of deferrals for tax purposes is no longer required. ATCO Electric nonetheless requested deferral treatment for the substantively enacted federal and provincial statutory income tax rates of 15 per cent and 10 per cent, respectively and submitted that a statutory income tax rate change could have a material impact on its income taxes and would be beyond its control. It added that carrying costs on the deferral account balance will be applied in accordance with AUC Rule 023.

91. ATCO Electric stated that, should the Commission not approve the requested recovery of provincial FIT, it is requesting approval of the continuation of the existing income taxes deferral account covering the substantively enacted federal and provincial statutory income tax rates of 15 per cent and 10 per cent, respectively, income tax deductible capital costs, and deductions of deferrals for tax purposes.

Commission findings

92. Because the statutory federal and provincial income tax rates are set by the applicable level of government, they are outside the control of ATCO Electric and are not reasonably able to be forecast by ATCO Electric. ATCO Electric's forecast of federal and provincial taxable income and federal and provincial temporary differences included in the omissions and updates filing is $177.9 million for 2013[49] and $225.3 million for 2014[50] with resulting forecast income

[49] Exhibit 188.02, Schedule 7-2. Federal taxable income of $18.0 million (line 3) plus federal temporary differences of $159.9 million (line 19) equals $177.9 million. The provincial numbers are $18.1 million (line 11) and $159.8 million (line 23) for a total of $177.9 million.

taxes of $48.2 million in 2013 and $59.6 million in 2014. The Commission finds that these forecast income tax amounts are significant and changes in the income tax rates would have an impact on these amounts.

93. In Section 14.7 of this decision the Commission has approved the inclusion of only federal FIT in the revenue requirements for ATCO Electric for 2013 and 2014. As a result, any variance between the forecast and actual items that make up the temporary differences will have an impact on the provincial income taxes that ATCO Electric actually pays in 2013 and 2014.

94. The Commission considers that the issue of income tax deductible capital costs is continually evolving as a result of ongoing cases between corporations and the Canada Revenue Agency. Therefore, the Commission finds that forecasting these types of income tax deductions is quite difficult. With regard to the deduction of deferrals for income tax purposes, the Commission also considers that it would be quite difficult to forecast the balances in all of the deferral accounts that have been established for ATCO Electric, especially the direct assigned capital projects deferral account that is dependent upon so many factors.

95. The Commission approves the deferral account for the statutory federal and provincial income tax rates for 2013 and 2014, along with the income tax rates used in the calculation of the federal FIT amounts for 2013 and 2014. The Commission also approves ATCO Electric's request to continue the deferral treatment for the income tax deductible capital costs and the deduction of deferrals for income tax purposes for 2013 and 2014.

96. The Commission directs ATCO Electric, in the compliance filing, as part of the updated Section 1, Attachment 3 schedule to be submitted, to do the following:

- remove the placeholder amount for the provincial FIT rates for 2013 and 2014
- include placeholder amounts for the provincial forecast of income tax deductible capital costs for 2013 and 2014
- include placeholder amounts for the provincial deduction of deferrals for income tax purposes for 2013 and 2014

5.1.9 Defined benefit pension costs

97. As detailed in Schedule 29-6 of the application, ATCO Electric included forecast defined benefit pension payments of $4.7 million in 2013 and $4.4 million in 2014. These amounts are comprised of special payments (past service) and current service payments, and are split between O&M and capital. ATCO Electric indicated that these payment amounts were calculated based on a 32 per cent contribution rate. In response to information request UCA-AE-007,[51] ATCO Electric provided more information about the basis for the 32 per cent placeholder.

98. ATCO Electric requested a deferral account for the defined benefit pension payment amounts in 2013 and 2014 and advised that, while the existing actuarial pension plan valuation covers the period 2010 to 2012, an updated valuation was required to be completed as of

[50] Exhibit 188.02, Schedule 7-2. Federal taxable income of $(33.6) million (line 3) plus federal temporary differences of $258.9 million (line 19) equals $225.3 million. The provincial numbers are $(33.5) million (line 11) and $258.9 million (line 23) for a total of $225.4 million.

[51] Exhibit 51.01.

December 31, 2012, to cover the 2013 to 2014 test period. The requested deferral account, subject to the Commission-directed 50 per cent cost of living adjustment cap detailed in Decision 2011-391[52] and/or the outcome of a future ATCO utilities common matters application, would flow-through the impact of any changes between the actual and forecast defined benefit pension payments. ATCO Electric submitted that the results of an updated actuarial pension plan valuation could have a material impact on its revenue requirement and is outside of its control.

Commission findings

99. The Commission agrees with ATCO Electric, with respect to costs related to an updated actuarial defined benefit pension plan valuation, that the events are outside the control of the company, are therefore not able to be reasonably forecast, and that forecasting differences could result in a material gain or loss.

100. The Commission acknowledges that the updated actuarial pension plan valuation to be completed as of December 31, 2012, was not available during the time the hearing was conducted, and that the as-filed placeholder amounts requested for 2013 and 2014 are in the amounts of $4.7 million and $4.4 million respectively. However, the Commission considers that this valuation should now be available to ATCO Electric, and it should be able to calculate the resulting impact on its forecast defined benefit pension costs for 2013 and 2014. The Commission finds that this additional information would be beneficial in assessing ATCO Electric's request for a deferral account for these costs.

101. Therefore, the Commission directs ATCO Electric, as part of the compliance filing, to submit the details of the actuarial pension plan valuation that was scheduled to be completed as of December 31, 2012, and to include the resulting impact on the defined benefit pension plan costs for 2013 and 2014 that were included in the application. These impacts should not be reflected in the revenue requirements included in the compliance filing.

102. In paragraph 36 of its written argument,[53] under the heading "ATCO Utilities Common Pension Matters," ATCO Electric stated that a continuation of the current pension costs placeholders will be required. The Commission considers that these placeholders refer to the $4.7 million and the $4.4 million discussed in the context of this section of the decision. However, if ATCO Electric does require approval of any other placeholders regarding pension costs that are not covered by the $4.7 million and the $4.4 million, it should include such a request in the compliance filing and clearly state what is being requested.

5.1.10 Ability to flow through dollar for dollar

103. As explained in paragraph 32 of this decision, ATCO Electric requested that it continue to be able to flow through certain items on a dollar for dollar basis. It submitted that changes to the revenue requirement that are related to statutory changes or Commission decisions are not reasonably able to be forecast and are not within its control. ATCO Electric added that items could arise within a short period of time that would not allow it sufficient time to defer resulting cost implications to a subsequent application. ATCO Electric indicated that it has not included any costs in the application for these types of events.

[52] Decision 2011-391: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.), 2011 Pension Common Matters, Application No. 1606850, Proceeding ID No. 999, September 27, 2011.
[53] Exhibit 239.01.

Commission findings

104. The deferral accounts related to legislative changes or Commission decisions have been long-standing deferral accounts approved by the Commission and its predecessor. However, as these deferral accounts have not had, and are not forecast to have, any costs arising from these matters, the Commission has considered whether it is necessary to continue to provide for these deferral accounts.

105. In examining the merits of continuing to provide for these deferral accounts, the Commission has, consistent with past practice, looked to several factors to guide its determination on the facts of this proceeding. Those factors, as articulated in Decision 2003-100,[54] are the "[m]ateriality of the forecast amount," the "[u]ncertainty regarding the accuracy and ability to forecast the amount," "[w]hether or not the factors affecting the forecast are beyond the utility's control," and "[w]hether or not the utility is typically at risk with respect to the forecast amount."[55]

106. In addition, in Decision 2010-189, the Commission confirmed its predecessor's position that deferral accounts should not be for the sole benefit of either the company or the customer.

107. These five factors, when applied to ATCO Electric's request to establish a deferral account to flow through any costs related to legislative changes, do not support the continued provision of this deferral account. The materiality of such a change is unknown and it cannot be said with any certainty that any costs that could arise from a legislative change would be of a material nature. Although there have been legislative amendments to the *Electric Utilities Act* and regulations in the past, these changes have not resulted in any requests for costs required to be flowed through on a dollar for dollar basis in past deferral account applications. As well, the Commission understands that it has been the practice of the Alberta government to consult with parties who may be impacted by changes to legislation before such changes are enacted. The Commission would not expect this historical practice to change over the test period. Consequently, the Commission is not persuaded by the position of ATCO Electric that it would be unable to react to the consequences of such a change during the 2013-2014 test period were such a change to occur. Therefore, although a legislative change may be outside the control of ATCO Electric, on balance, the Commission is not persuaded that there is any continued need to maintain a deferral account of this nature.

108. With regard to the request of ATCO Electric to continue to flow through dollar for dollar to the transmission tariff for 2013 and 2014, costs which arise from Commission-approved tariffs for 2013 and 2014 with respect to ATCO Electric or any other industry participant, including the AESO, the Commission finds it reasonable to continue this practice. ATCO Electric would be unable to forecast the outcome of Commission proceedings which could have the impact of imposing costs on it to which it would be unable to react. As these costs would only arise as a consequence of a Commission proceeding, the Commission would be in a position to determine the impact of its decision on ATCO Electric, at that time.

109. The Commission therefore approves ATCO Electric's request to continue the ability to flow through dollar for dollar to the transmission tariff for 2013 and 2014, costs which arise as a

[54] Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application Phase 1, Application No. 1292783, December 2, 2003.
[55] Decision 2003-100, page 116.

consequence of the Commission approved tariffs for 2013 and 2014 with respect to ATCO Electric or any other industry participant, including the AESO.

110. Any requested dollar amounts for such flow-throughs that are made by ATCO Electric relating to the 2013 and 2014 transmission tariffs would still have to be reviewed and approved by the Commission for accuracy and relevance. The Commission directs ATCO Electric, in the compliance filing, to include the approval for this continuation, on the updated Section 1, Attachment 3 schedule to be submitted.

5.2 Status of placeholders

111. ATCO Electric requested the approval of placeholders relating to ATCO I-Tek rates, ATCO Utilities corporate costs, pension costs, return on equity and the common equity ratio. The Commission understands that, when ATCO Electric prepared the application, there were certain items included that may be impacted by other applications that are either underway or scheduled to be submitted to the Commission. ATCO Electric requested approval to treat these certain items as placeholders pending the outcome of the other applications. Once the other applications are finalized ATCO Electric will revise the placeholder amounts as required and calculate the resulting impact on the revenue requirements for the 2013-2014 test period. The resulting impact on the revenue requirements would be included in the annual filing for adjustment balances that ATCO Electric submits to the Commission for approval.

112. In the omissions and updates filing, ATCO Electric included revised attachments 3 and 3.1 from Section 1 of the application. These revised attachments[56] are entitled as follows:

- Revised Section 1, Attachment 3: Placeholder and Other Outstanding Matters Summary – Updated for O&U

- Revised Section 1, Attachment 3.1: Placeholder for Transmission Direct Assigned – Updated for O&U

113. These revised attachments contain information related to all of the placeholders as well as the deferral accounts for which ATCO Electric requested approval.

114. As previously explained in paragraph 26 of this decision, the Commission has directed ATCO Electric to update Attachment 3 to remove any request for a placeholder for the terms and conditions of service. During the oral hearing, Commission counsel requested more information from ATCO Electric about the composition of some of the figures on Attachment 3.1.[57] The figures included the depreciation expense/amortization figures on lines four and five and the capital cost allowance figures on lines 15, 16 and 17. This information was provided by way of an undertaking response.

115. Included in the undertaking response was the following:

> In preparing the response for this undertaking, ATCO Electric reviewed the detailed calculations used to derive both the 2013 and 2014 depreciation expense and Capital Cost Allowance (CCA) placeholder amounts outlined in the revised placeholder schedule contained in ATCO Electric's Omissions and Updates Application (Exhibit 0117.17.AE-

[56] Exhibit 117.17.
[57] Transcript, Volume 3, pages 460-461.

> 1989). During this review, it was determined there were calculation errors for 2013 and 2014 depreciation and CCA.
>
> ATCO Electric will correct these calculation errors in depreciation expense and CCA placeholders as part of its compliance filing.[58]

116. The Commission considers that these errors may have been discovered and corrected earlier had the detailed calculations used to derive the depreciation expense/amortization and capital cost allowance placeholder amounts on the revised Section 1, Attachment 3.1 schedule been provided as part of the omissions and updates filing. For the purposes of verifying the calculation of the direct assigned capital projects deferral accounts for 2013 and 2014 in future years (the establishment of such deferral account being approved earlier in Section 5.1.4 of this decision), it would be beneficial to have the detailed calculations related to the forecast amounts. The Commission therefore directs ATCO Electric, in the compliance filing, to include details of the calculations used to derive the depreciation expense/amortization and capital cost allowance placeholder amounts that are included on the updated Section 1, Attachment 3.1 schedule that will be submitted as part of the compliance filing. These details should include the relevant capital asset categories and applicable depreciation rates, as well as the relevant capital cost allowance classes and applicable capital cost allowance rates.

5.2.1 ATCO I-Tek rates

117. ATCO I-Tek is an affiliate company of ATCO Electric that provides information technology services to a number of the ATCO Ltd. group of companies, including ATCO Electric. In the application, ATCO Electric advised that the rates ATCO I-Tek charges to ATCO Electric for 2010 to 2012, as well as the forecast rates included in the current application for 2013 and 2014, are not finalized and are the subject of the ATCO Utilities Evergreen II proceeding.[59] Because the ATCO Utilities Evergreen II proceeding is not finalized, ATCO Electric requested that the ATCO I-Tek rates included in the application for 2013 and 2014 be treated as placeholders.

Commission findings

118. The Commission grants the request made by ATCO Electric to treat the ATCO I-Tek rates used in the preparation of the revenue requirements for the 2013-2014 test period as placeholders, pending the outcome of the ATCO Utilities Evergreen II proceeding. It is reasonable that any relevant findings/directions made by the Commission in its decision on the ATCO Utilities Evergreen II proceeding that impact the ATCO I-Tek rates for 2013 and 2014 be reflected in the revenue requirements for those years.

119. ATCO Electric included the total forecast dollar amounts for 2013 and 2014 for ATCO I-Tek charges on the placeholder summary schedule of Section 1, Attachment 3 of the application. ATCO Electric updated these amounts on the revised Section 1, Attachment 3 schedule of the omissions and updates filing.[60] The forecast dollar amounts on the revised Section 1, Attachment 3 schedule can be traced to the revised schedules 30-13 and 30-14 that were also submitted as part of the omissions and updates filing.[61] The Commission understands

[58] Exhibit 162.01, page 2 of 2.
[59] Proceeding ID No. 240.
[60] Exhibit 117.17.
[61] Exhibit 117.15.

that these forecast dollar amounts are arrived at by using the ATCO I-Tek rates approved for 2013 and 2014 on an interim basis and the units included on the revised schedules 30-13 and 30-14. The Commission is unable to approve the total forecast dollar amounts for 2013 and 2014 for ATCO I-Tek charges that were included on the placeholder summary schedule, because they include both volumes and rates, and the volumes are not subject to placeholder treatment.

120. To clarify this situation, the Commission directs ATCO Electric, in the compliance filing, to remove the dollar amounts for the ATCO I-Tek placeholders from the Section 1, Attachment 3 schedule that is submitted as part of the compliance filing; and further directs ATCO Electric to include a note to the "IT Placeholders" area of the Section 1, Attachment 3 schedule that is submitted as part of the compliance filing, which explains that the ATCO I-Tek rates only are subject to placeholder treatment.

121. During the oral hearing, Commission counsel questioned ATCO Electric witnesses about the information contained in schedules 30-13 and 30-14 of the application.[62] Commission counsel inquired about whether the information in schedules 30-13 and 30-14 was entirely for the transmission function or the entire company, including the distribution function. One of the ATCO Electric witnesses submitted that, subject to check, the information was for transmission and common but not distribution. The witness also stated that, if the information was for the whole company, it would be broken down to show what was for transmission only. No subsequent update was provided by ATCO Electric.

122. In reviewing the information contained in schedules 30-13 and 30-14 of the application (and the updated schedules 30-13 and 30-14 of the omissions and updates filing) the Commission finds that, while the forecast ATCO I-Tek charges included under the GTA category "Transmission"[63] are entirely for the transmission function, the amounts included under the "Isolated," "General," "Common" and "Corporate" categories of these schedules are the total amounts before allocation. The Commission considers that, in order to aid in the true-up of the ATCO I-Tek rates placeholders for the transmission function, it is important to know how much of the forecast dollar amounts in schedules 30-13 and 30-14 is for transmission only. In order to do this, the information in schedules 30-13 and 30-14 should be supplemented with additional schedules that show the forecast ATCO I-Tek units and resulting dollars for ATCO Electric's transmission function only. Therefore, the Commission directs ATCO Electric, in the compliance filing, to include schedules 30-13 and 30-14, updated to reflect all of the directions in this decision; and also directs ATCO Electric, in the compliance filing, to include supplementary schedules in the format of schedules 30-13 and 30-14 that includes only the units and dollars reflected in the compliance filing that are applicable to its transmission function.

5.2.2 ATCO Utilities corporate costs

123. In its application, ATCO Electric explained that the corporate costs allocated to it by its parent company for 2012 were directed by the Commission to be treated as a placeholder pending a determination made by the Commission in a future ATCO Utilities corporate costs allocation methodology application. In its argument, ATCO Electric advised that a separate proceeding related to corporate costs was completed in 2012. ATCO Electric indicated that, for the 2013 and 2014 test periods, it has included placeholders of $16.4 million and $16.9 million respectively. These amounts represent the forecast amount of corporate costs allocated to

[62] Transcript, Volume 3, pages 515-516.
[63] Exhibit 117.15, revised Schedule 30-13, line 380; Exhibit 117.15, revised Schedule 30-14, line 380.

ATCO Electric for 2013 and 2014. ATCO Electric added that these placeholders are based on the 2012 forecast of $15.8 million escalated by an inflation factor of 3.5 per cent per year.

124. ATCO Electric stated that the 2013 and 2014 placeholders for corporate costs do not reflect any forecast change in the percentage of corporate costs allocated to ATCO Electric. ATCO Electric indicated that, as part of the compliance filing, it would true up its 2013 and 2014 placeholders, to the Commission-approved allocation formula applied to the total approved forecast 2013 and 2014 corporate costs. ATCO Electric advised that the total 2013 and 2014 forecast corporate costs will be based on the Commission approved total corporate costs for 2012, inflated by 3.5 per cent per year.

Commission findings

125. ATCO Electric included details about the calculation of the $16.4 million for 2013 and the $16.9 million for 2014 included in the placeholder amounts. These details are shown in schedules 25-8 and 25-9 of the application. It is clear to the Commission after reviewing the schedules in Section 25 of the application that the $16.4 million and the $16.9 million are the corporate costs forecast to be allocated to all of ATCO Electric, which consists of the distribution and transmission functions.

126. On the placeholder summary schedule of Section 1, Attachment 3 of the application (as well as the omissions and updates filing) ATCO Electric included a figure of 33.9 per cent for the placeholder relating to corporate costs. Commission counsel questioned the ATCO Electric general panel about this during the oral hearing.[64] Commission counsel was interested in finding out how much of the $16.4 million for 2013 and the $16.9 million for 2014 was for the transmission function. In response, the ATCO Electric witness provided the following testimony:

> A. MR. MCNABB: So Schedule 25-3, which is for ATCO Electric in total, you see -- and you may not have it in front of you. So it's -- line 38 shows 16.4 and 16.9 for 2013 and 2014. And then if we go to 25-3-T, you will see the head office cost for '13 and '14 just for transmission of 8.4 and 8.8 million respectively. Those are the placeholders.[65]

127. It is clear to the Commission from reviewing the application, the transcript and the argument of ATCO Electric that the placeholder for the corporate costs for the transmission function being requested by ATCO Electric is $8.4 million for 2013 and $8.8 million for 2014. The Commission considers that ATCO Electric is not requesting placeholder treatment for the 33.9 per cent that is included on the placeholder summary schedule of Section 1, Attachment 3.

128. The $8.4 million and the $8.8 million are arrived at through a series of calculations. First, the total forecast allocated costs to ATCO Electric (transmission and distribution) for 2013 and 2014 need to be determined. Referring to Schedule 25-8 of the application, it is clear that the overall total forecast corporate costs for 2012 to be allocated to the entire ATCO Ltd. group of companies are $46.0 million. Inflating this amount by 3.5 per cent results in the forecast total corporate costs for 2013 to be allocated to the entire ATCO Ltd. group of companies being $47.6 million. A similar calculation results in an amount of $49.3 million for 2014.

[64] Transcript, Volume 3, pages 517-519.
[65] Transcript, Volume 3, page 518, lines 23-25; Transcript, Volume 3, page 519, lines 1-3.

129. Using the allocation percentages shown in Schedule 25-8 of the application, which result from using actual figures from 2010 as the input values into the allocation methodology, shows that ATCO Electric's combined distribution and transmission share of the total corporate costs is $16.4 million for 2013 and $16.9 million for 2014. These amounts of $16.4 million and $16.9 million are then allocated between the distribution and transmission functions using the methodologies described in Section 27 of the application. In this case, the resulting figures for the transmission function were $8.4 million for 2013 and $8.8 million for 2014.

130. On August 9, 2013, the Commission issued Decision 2013-293[66] in accordance with the ATCO Utilities corporate costs compliance filing pursuant to Decision 2013-111.[67] In Decision 2013-293, the Commission approved total forecast corporate costs of $42.4 million for 2012, to be allocated to the entire ATCO Ltd. group of companies. ATCO Electric's combined distribution and transmission share of the $42.4 million was approved at $11.4 million.

131. In Decision 2013-111, the Commission approved the methodology to be used to allocate the total forecast corporate costs for 2012 and for subsequent years. This approved methodology causally allocates the costs for the internal audit function and the human resources function, and uses a formula to allocate the remaining costs. This formula consists of an equal weighting to be given to the following: labour expense, total assets, and revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation from the allocation methodology calculations. In Decision 2013-293, the Commission approved the use of audited financial data from two years prior to the test year as inputs into the allocation formula.

132. The Commission considers that, pursuant to Decisions 2013-111 and 2013-293, the issue of the allocation of corporate costs for the years 2013 and 2014 is resolved. Consequently, the Commission finds that there is no need for a placeholder for these costs as ATCO Electric requested. The Commission therefore denies the request of ATCO Electric for a placeholder for corporate costs. The Commission directs ATCO Electric, in the compliance filing, to remove corporate costs from the Section 1, Attachment 3 schedule that will be included as part of the compliance filing.

133. With respect to the amount of corporate costs to be allocated to ATCO Electric's distribution and transmission function for 2013 and 2014, the Commission first has to determine the total forecast corporate costs for 2013 and 2014 to be allocated to the entire ATCO Ltd. group of companies. ATCO Electric has requested that this be equal to the total approved costs for 2012 plus inflation of 3.5 per cent in 2013 and 2014. The 3.5 per cent inflation rate is what ATCO Electric requested as labour inflation for 2013 and 2014. The Commission considers that the corporate costs consist of not only labour costs, but other costs as well, and the inflation rates approved for labour and other cost elements in this decision should, in principle, be reflected in the corporate costs, to the extent possible.

134. In Section 5.4.1.1 of this decision, the Commission has approved labour inflation rates of 3.5 per cent for 2013 and 3.5 per cent for 2014; and the Commission has approved inflation rates for other expenses of 2.2 per cent for 2013 and 2.1 per cent for 2014. While Schedule 25-9 of the application includes a functional analysis of the various corporate cost areas, this is not further

[66] Decision 2013-293: The ATCO Utilities, Corporate Costs – Compliance Filing to the Alberta Utilities Commission Decision 2013-111, Application No. 1609573, Proceeding ID No. 2594, August 9, 2013.

[67] Decision 2013-111: The ATCO Utilities, Corporate Costs, Application No. 1608510, Proceeding ID No. 1920, March 21, 2013.

fully broken down into labour and other, with the exception of the corporate office – supplies and corporate office – office rent functions. The Commission considers that, because of the effort required to break down all of the functional corporate cost areas into labour and other, and the relatively small difference between the inflation rates approved for labour and other, it will not be necessary for ATCO Electric to provide such an analysis. Since the corporate office – supplies and corporate office – office rent functions are already broken down, the Commission finds that these functions should be adjusted by the inflation rate approved for other expenses. The remaining functions should be adjusted by the inflation rates approved for labour.

135. In the compliance filing, the Commission directs ATCO Electric to recalculate and resubmit schedules 25-8 and 25-9. The Commission further directs that separate schedules 25-8 be prepared for each of 2013 and 2014. The Commission directs the following with respect to the Schedule 25-8 for 2013 that will be submitted as part of the compliance filing:

- The schedule is to be updated to remove the 2012 forecast amounts included in the application and include the 2012 approved amount from Decision 2013-293, which is $42.4 million.
- The schedule is to include the 2013 forecast amounts that result from applying inflation of 2.2 per cent to the 2012 approved amounts from Decision 2013-293 for the corporate office – supplies and corporate office – office rent functions; and applying inflation of 3.5 per cent to the 2012 approved amounts from Decision 2013-293 for all other functions.
- The schedule is to be updated to use the allocation methodology approved in Decision 2013-111, including the causal allocations of the internal audit function and the human resources function.
- The schedule is to be prepared using the actual audit hours for the years 2009, 2010 and 2011 in calculating the allocation of the internal audit function costs.
- The schedule is to be prepared using the actual headcount information at December 31, 2011, in calculating the allocation of the human resources function costs.
- The schedule is to be prepared using the actual results from the year 2011 as inputs in the allocation formula, including the December 31, 2011, results of ATCO Gas Australia.
- The schedule is to include details of how the allocation percentages for the General, CU Public and CU Inc. Public categories were arrived at.
- The schedule is to include details of how the internal audit function and human resource function allocations were arrived at.

136. The Commission directs the following with respect to the Schedule 25-8 for 2014 that will be submitted as part of the compliance filing:

- The schedule is to be updated to remove the 2012 forecast amounts included in the application and include the 2012 approved amounts from Decision 2013-293, which total $42.4 million.
- The schedule is to include the 2014 forecast amounts that result from applying inflation of 2.1 per cent to the 2013 forecast amounts for the corporate office – supplies and

corporate office – office rent functions; and applying inflation of 3.5 per cent to the 2013 forecast amounts for all other functions.

- The schedule is to be updated to use the allocation methodology approved in Decision 2013-111, including the causal allocations of the internal audit function and the human resources function.
- The schedule is to be prepared using the actual audit hours for the years 2009, 2010 and 2011 in calculating the allocation of the internal audit function costs.
- The schedule is to be prepared using the actual headcount information at December 31, 2011, in calculating the allocation of the human resources function costs.
- The schedule is to be prepared using the actual results from the year 2011 as inputs in the allocation formula, including the December 31, 2011, results of ATCO Gas Australia.
- The schedule is to include details of how the allocation percentages for the General, CU Public and CU Inc. Public categories were arrived at.
- The schedule is to include details of how the internal audit function and human resource function allocations were arrived at.

137. The Commission directs the following with respect to the Schedule 25-9 that will be submitted as part of the compliance filing:

- The amounts with respect to 2010 and 2011 are to be removed from the schedule.
- The schedule is to include the amounts for 2012, 2013 and 2014 on a functional basis for the total corporate costs to be allocated to the entire ATCO Ltd. group of companies, separated out among General, CU Public, and CU Inc. Public.
- The schedule is to include the amounts for 2012, 2013 and 2014 on a functional basis for only the corporate costs that are allocated to ATCO Electric, separated out among General, CU Public, and CU Inc. Public.

138. The 2013 and 2014 forecast amounts for allocated corporate costs for ATCO Electric's transmission function that are to be included in the compliance filing will be based on the amounts resulting from the directions included in paragraphs 135, 136 and 137 of this decision. The amount to be allocated to the transmission function will be calculated by using the Commission-approved cost allocations for corporate administration and general costs between transmission and distribution. These approved cost allocations are discussed in Section 13.1 of this decision. The Commission directs that, in the compliance filing, ATCO Electric use the applicable approved cost allocations for corporate administration and general costs from Section 13.1 of this decision in calculating the transmission function's corporate costs for 2013 and 2014. The Commission further directs that details of how the allocated corporate costs for the transmission function were calculated be included as part of the compliance filing.

5.2.3 Common equity ratio and return on equity percentage

139. In Decision 2011-474, the Commission issued its findings on the generic cost of capital proceeding and set the common equity ratio and return on equity percentages for 2011 and 2012 for ATCO Electric. As detailed in paragraph 168 of Decision 2011-474, the Commission set the allowed return on equity percentage for 2013 at 8.75 per cent on an interim basis. The

Commission added that it would initiate a proceeding in due course to establish a final allowed return on equity percentage for 2013. In the application, ATCO Electric used 8.75 per cent as the return on equity percentage for both 2013 and 2014, as evidenced in Schedule 28-1 of the application.

140. The common equity ratio of 37 per cent for ATCO Electric's transmission function established in Decision 2011-474 was set until changed by the Commission. In the application, ATCO Electric used 37 per cent as the common equity ratio for both 2013 and 2014, as evidenced in Schedule 28-1 of the application.

141. Decision 2011-474 was the subject of a review and variance proceeding. At paragraph 39 of Decision 2012-154,[68] which addressed the application for the review and variance of Decision 2011-474, the Commission made the following determination:

> 39. The review panel notes that the Commission sought to have the issues raised by the *Stores Block* decision of the Supreme Court of Canada, including the issue of stranded assets, resolved when the Commission initiated the Utility Asset Disposition Rate Review Proceeding (Proceeding ID No. 20) on April 2, 2008. Following a number of procedural steps, Proceeding ID No. 20 was suspended on November 20, 2008. Given this and the submission of ATCO Utilities, the review panel considers that the issue of stranded assets and who bears the risk in relation to stranded assets should be evaluated in the context of the relevant legislation and case law and therefore expects to either re-initiate Proceeding ID No. 20 or initiate a generic proceeding regarding asset disposition and stranded assets. The Commission will establish this proceeding after the issuance of a Commission decision on the Rate Regulation Initiative (Proceeding ID No. 566). (footnote omitted)

142. In light of the proceedings that could impact the common equity ratio and the return on equity percentage for ATCO Electric's transmission function for the years 2013 and 2014, ATCO Electric requested that the amounts used for these in the current application be set as placeholders.

Commission findings

143. The Commission has re-initiated Proceeding ID No. 20 regarding the issue of utility asset dispositions and stranded assets. The Commission has also initiated Proceeding ID No. 2191 regarding the generic cost of capital for 2013. The Commission considers that the outcome of these proceedings may impact both the common equity ratio and the return on equity percentage for ATCO Electric's transmission function for 2013 and/or 2014. Therefore the Commission grants the request by ATCO Electric that the common equity ratio of 37 per cent and the return on equity percentage of 8.75 per cent be treated as placeholders for 2013 and 2014. The Commission directs ATCO Electric, in the compliance filing, to use 8.75 per cent as the return on equity percentage for 2013 and 2014, and to use 37 per cent as the common equity ratio for 2013 and 2014.

[68] Decision 2012-154: Decision on Request for Review and Variance of AUC Decision 2011-474, 2011 Generic Cost of Capital, Application Nos. 1608120, 1608122, 1608126, 1608127, 1608129 and 1608136, Proceeding ID No. 1697, June 4, 2012.

5.2.4 Summary of placeholder accounts

144. It would be convenient to have an updated placeholder summary schedule that reflects all of the applicable directions that have been made in this decision. The Commission therefore directs ATCO Electric, as part of the compliance filing, to file an updated Attachment 3 schedule and an updated Attachment 3.1 schedule from Section 1 of the application, that reflects and incorporates the applicable directions contained in this decision.

5.3 Other items

145. This section addresses the following matters raised by the interveners:

- deferral account treatment for IFRS
- changes to ATCO Electric's internal organizational structure

5.3.1 Deferral account for International Financial Reporting Standards

146. In the application, ATCO Electric advised that consistent with its 2011-2012 GTA, it prepared the current application in accordance with the guidelines provided in the AUC's Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards* (AUC Rule 026). ATCO Electric included a schedule in Section 1 of the application (Attachment 4) in which it compared the filing approach to the guidelines in AUC Rule 026. It did not request any type of direct deferral account with respect to IFRS.

147. ATCO Electric responded to some information requests regarding the International Accounting Standards Board (IASB), the body which oversees IFRS, and its possible review of the accounting for rate-regulated activities.[69] There was also some cross-examination around this topic during the oral hearing.[70]

148. The CCA submitted that the IFRS deferral account approved in Decision 2011-134 for ATCO Electric should be continued into the 2013 and 2014 test years. The CCA stated that the IASB has decided to restart its previous project on rate-regulated activities and has also discussed whether to develop an interim standard for this area. The CCA indicated that such interim guidance would allow the continuation of accounting practices in accordance with pre-changeover standards.

149. The CCA submitted that, if this continuation of pre-changeover standards were permitted, it would impact one of the main changes affecting the determination of the revenue requirements, namely, the change in the treatment of indirect capital overhead costs. Under the current IFRS, and as allowed in AUC Rule 026, indirect capital overhead costs are expensed. The CCA argued that a change to pre-IFRS standards would allow ATCO Electric to treat indirect overhead costs as capital, which could have a material impact on the utility's revenue requirements.

150. The CCA added that, in approving the IFRS deferral account for 2011-2012, the Commission made its decision on the basis that the current version of IFRS may not be the final

[69] Please refer to the response to UCA-AE-054 in Exhibit 51.01; and the response to CCA-AE-011 in Exhibit 53.01.
[70] Transcript, Volume 2, pages 358-365.

version and submitted that the same situation applies currently, as changes are certainly forthcoming in the near term.

151. ATCO Electric rejected the CCA's claim that changes are certainly forthcoming in the near term and submitted that it does not foresee any issues arising in the test period with respect to the implementation of new standards. It indicated that it is aware of the IASB restarting the project on rate-regulated activities and, based on its review, it does not expect the implementation of any new standards in this area prior to 2015, which is outside the test period.

Commission findings

152. The CCA is correct that the IASB has restarted its previous project on rate-regulated activities. However, the Commission cannot conclude that an interim standard would allow the continuation of accounting practices in accordance with pre-changeover standards, as neither the CCA nor the applicant have submitted any supporting evidence that this would be permitted. The Commission accepts that it is possible that this may occur, as evidenced by the statement from the Accounting Standards Board of Canada included in the preamble to information request CCA-AE-011.[71]

153. The latest information on the record of this proceeding regarding the IASB's rate-regulated activities project and possible interim standard, came from an exchange between counsel for the CCA and ATCO Electric's witness during the oral hearing. This information is as follows:

> Q. MR. WACHOWICH: A couple questions, because a hearing today wouldn't be complete unless we use the initials IFRS. And I'm assuming, Mr. McNabb, those will go to you as well. And just to confirm sort of the current -- it's built on a foundation of sand it seems at times, IFRS. But the current status is that as of September 2012, the Accounting Standards Board, quote: (as read)
> "As we understand it, decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate regulated activities by a additional year to January 1, 2014."
> Is that your current understanding, or can you take that subject to check?
> A. MR. MCNABB: I'll take it subject to check.
> Q. (As read)
> "And further, we understand it has been advised to parties the International Accounting Standards Board (IASB) decided to restart its previous project on rate regulated activities with the development of a discussion paper. The IASB also discussed but did not decide whether to develop an interim IFRS and considered some alternatives for what type of interim IFRS might be

[71] Exhibit 43.01.

appropriate. At its October 2012 immediate meeting, the IASB's IFRS advisory council will be asked for input on whether the IASB should develop an interim IFRS."
I think I got that on all the acronyms correct.
Can you provide any update on that issue as it pertains to ATCO Electric TFO?
A. MR. MCNABB: So ATCO Electric along with ATCO adopted IFRS effective January 1, 2011. So we have made the transition to IFRS. Both our financial statements were prepared in '11, comparatives in '10 have been audited and approved; and we have made the adjustments also for regulatory purposes in '11, '12, and also in the '13, '14 GTA.
There is a few differences between how we record things under IFRS for financial statement purposes versus regulatory purposes. One of those is the fact that we continue to record deferrals under regulatory, whereas under IFRS you're not allowed to.
So if -- so for us, the way we record IFRS, ATCO and ATCO Electric, we do not record deferrals. But if for some reason through what you have just discussed, that somewhere along the way it is determined that deferrals can be recorded under IFRS, that would not change the way that we account for things for regulatory purposes.[72]

154. The Commission considers that this latest information on the record provides no certainty about an interim standard being issued by the IASB, or what the scope of a possible interim standard might be. This information only indicates that a meeting was scheduled to be held in October, 2012 but there is no material regarding the outcome of such a meeting on the record of this proceeding.

155. The Commission understands the impact that a change to the treatment of indirect overhead costs would have on revenue requirement. Allowing indirect overhead costs to be capitalized would result in a reduction to expenses and an increase in rate base, with the net short term impact being a reduction in revenue requirement. However, based on the material provided during the proceeding, there is no evidence that this treatment will be permitted during the test period.

156. However, it is a fact that an IASB project on rate-regulated activities is currently in progress, and it would be helpful to have more information in assessing the CCA's request for a deferral account for IFRS. Therefore, in the compliance filing, the Commission directs ATCO Electric to provide a status update and a summary of the activities that have occurred since September, 2012 on the IASB's rate-regulated project, including information regarding any interim standards, exposure drafts or discussion papers. The Commission will make a finding regarding the CCA's request for a deferral account for IFRS in its subsequent decision on ATCO Electric's compliance filing.

[72] Transcript, Volume 2, page 358, lines 3-25; page 359, lines 1-25; page 360, lines 1-4.

5.3.2 Organizational structure

157. In the application, ATCO Electric indicated that in 2010 the company was restructured into two divisions, a capital projects division and an operations division. The capital projects division was established to manage the company's major transmission build, including all AESO direct assigned capital projects. The operations division was given responsibility for all remaining aspects of the business, including distribution and transmission (non-direct assigned capital projects, O&M) as well as the corporate administration and general costs and services. ATCO Electric included an organization chart in Section 1, Attachment 2 of the application to illustrate the new company structure. Further information was provided in response to information request UCA-AE-012.[73]

158. The UCA commented that ATCO Electric's organizational structure has a significant level of senior positions and added that it was concerned that it may be "top heavy." The UCA submitted that the entire parallel structure that ATCO Electric has built may become redundant when the level of direct assigned capital projects lessens. The UCA observed that ATCO Electric's organizational structure is larger than any other utility in Alberta and requested that this excessive bureaucracy be noted by the Commission in assessing the material cost increase in the application.

159. In addition, the UCA expressed concern that the level of full-time equivalents (FTEs) approved in the current application will be used to establish a new normal level of FTEs for the future. It requested that the Commission confirm that approval of any capital projects and the related FTEs be restricted to the 2013-2014 test period and not apply to any future period. The UCA submitted that the Commission should also direct ATCO Electric to justify its FTE levels in its next GTA relative to its anticipated construction activity. Last, the UCA requested the Commission to direct ATCO Electric, in its next GTA, to explicitly break out how FTEs added for capital purposes during the 2013-2014 test period have been redeployed or reduced within the context of construction activity at that time.

Commission findings

160. In paragraph 221 of its rebuttal evidence[74] ATCO Electric stated the following:

> This application deals with ATCO Electric Transmission function's 2013-2014 Revenue Requirement. ATCO Electric understands that it will need to justify future structures and costs as part of future regulatory applications dealing with 2015 and beyond.

161. This understanding was confirmed during the oral hearing during cross-examination of the ATCO Electric capital panel by counsel for the UCA.

> 10 Q. Thank you. Can I take you to Exhibit 116.01. And
> 11 that's the rebuttal filing. Pdf page 201, page 73,
> 12 paragraph 221.
> 13 A. MR. DECHAMPLAIN: I have that.
> 14 Q. Okay. That paragraph states: (as read)
> 15 "This application deals with ATCO
> 16 Electric transmission's functions 2013
> 17 to 2014 revenue requirement.

[73] Exhibit 51.01.
[74] Exhibit 116.01.

ATCO Electric understands that it will need to justify future structures and costs as part of future regulatory applications dealing with 2015 and beyond."
Am I correct in assuming, sir, that means that there's no request in this application to approve an established level of FTEs going forward beyond the test period?
A. MR. DECHAMPLAIN: In my mind, the Commission approves just and reasonable rates. We put forward a forecast mix of labour and contracts to execute that work. We have not forecasted the work beyond the test period nor forecasts the resourcing strategy to accomplish that work. So long answer to no, we don't have a complement for 2015 that we're asking the Commission to approve.
Q. And looking at our earlier discussion where you expect to see areas of growth, if, for example, you see fewer construction resources needed, you would reflect that in the future with your anticipated level of FTEs? If that shrinks, your numbers would presumably shrink accordingly?
A. MR. DECHAMPLAIN: Again, that would depend on the execution strategy in 2015 and beyond. To the extent that we would want to displace contractors, you may see more FTEs with a smaller base load. It depends how work is planned to get done.[75]

162. The record is clear that, in this application, ATCO Electric is requesting approval for FTEs and the revenue requirements associated with these FTEs for the 2013-2014 test period only. Parties to this proceeding are only examining and testing the revenue requirements for the 2013-2014 test period, and this decision and the subsequent decision on the compliance filing will only address the revenue requirements for 2013 and 2014. ATCO Electric is aware that it will have to justify the entirety of the revenue requirement included in its next GTA, including the number of forecast FTEs and capital projects. Interveners will also be given the opportunity to examine and test ATCO Electric's next GTA.

163. The Commission wishes to be clear that ATCO Electric should not follow an approach which primarily uses the observed costs and resources of the year immediately prior to the applied-for test period, or the updated forecast of the previous period, as the starting point for its subsequent increases in activities and costs. The Commission considers that, regardless of the organizational structure, ATCO Electric would be best to develop its forecasts from an assumed zero-base, which seeks to reassess the resources and costs required to fulfill its statutory duties on an annual basis, without assuming that costs are simply incremental to the actual or forecast costs of the preceding year.

164. During the examination and testing of ATCO Electric's next GTA, the interveners will be free to request ATCO Electric to break out how FTEs added for capital purposes during the 2013-2014 test period have been redeployed or reduced within the context of construction activity at that time.

[75] Transcript, Volume 4, page 675, lines 10-25; page 676, lines 1-17.

165. In view of the above, the Commission does not find it necessary to direct ATCO Electric as proposed by the UCA.

5.4 Key assumptions and forecasting methodology

166. ATCO Electric stated that growth in property, plant and equipment is impacting all aspects of this application and added that the forecast operating costs reflect the business impact of this growth in property, plant and equipment as well as regional market issues.

167. ATCO Electric advised that a separate forecast is developed for labour and non-labour costs. The total forecast labour costs are developed by preparing a plan of the FTEs required to perform the level of work forecast for the test years. For existing FTEs, the labour dollars are developed by multiplying FTEs by the actual salary. For additions to FTEs, the labour dollars are developed by multiplying the additional FTEs by the salary for that position. All forecast FTE additions during the test period are deemed to be hired at mid-year. These labour costs are then distributed to O&M or capital, depending on the nature of the work being done by the FTE. New labour costs are forecast in two parts. First are ongoing operational and administrative activities and second are new programs or projects.

168. ATCO Electric indicated that a FTE is defined as the measure that is used to quantify the portion of permanent or temporary person-years used or needed in a given position. A FTE is always less than or equal to one in relation to a position. Casual employees and work done by contractors are not factored into the FTEs.

169. ATCO Electric stated that, for other dollars relating to ongoing operational and administrative activities, the forecasts are based on historical spending requirements which are then adjusted up or down for known changes in work to be done in the forecast period. New operational and administrative activities are identified by senior management based on ongoing analysis of operational risks, system requirements and customer needs.

5.4.1 Inflation rates

170. ATCO Electric advised that the following inflation rates were used in the preparation of the forecast for the 2013-2014 test period.

Table 5. Assumptions – inflation[76]

	2013 (%)	2014 (%)
Labour	3.5	3.5
Contractors – all except direct assigned capital projects	6.0	6.0
Contractors – direct assigned capital projects	4.0	4.0
Contractors – direct assigned capital projects escalation	25.0	0.0
Other	2.2	2.1

171. In Section 10, paragraph 222 of the application ATCO Electric clarified that the 25 per cent escalation factor for contractors had been added to all forecasted direct assigned capital projects with the exception of projects included under the following categories:

[76] Exhibit 1, application, Section 1, paragraph 42.

- Eastern Alberta Transmission Line (EATL)
- Hanna Regional Transmission Development (HRTD)
- North East Transmission Development (NETD)

172. In response to a Commission question on an undertaking response, ATCO Electric clarified further that the 25 per cent escalation factor did apply to some direct assigned capital projects costs in 2014 as well.[77]

5.4.1.1 Inflation rates – labour

173. In the application, ATCO Electric submitted that increases for employees belonging to the Canadian Energy Workers Association (CEWA) in 2013 reflect the final year increase of a two-year collective agreement expiring December 31, 2013. The 3.5 per cent increase in 2014 for CEWA employees reflects ATCO Electric's forecast of the increase required, given the current labour market. ATCO Electric further submitted that the inflation increases in 2013 and 2014 for out-of-scope (non-union) employees are the same as the increases for CEWA employees and reflect ATCO Electric's forecast of the increases required, given the current labour market.

174. In response to information request UCA-AE-021(a),[78] ATCO Electric added that, besides the 3.5 per cent labour inflation, it had also included adjustments to labour costs for increased VPP eligibility where applicable. In addition, where applicable, it included promotional and progression increases including step increments of two per cent per year.

175. In response to information request UCA-AE-21(b), ATCO Electric submitted that, to determine the labour inflation rate, it had considered external market data obtained from various compensation survey organizations, government agencies, and professional organizations. More specifically, it made the following observations:

- The Conference Board of Canada forecast wage growth of 3.9 per cent in 2012 and 3.4 per cent in 2013.
- The Province of Alberta's Occupational Demand and Supply Outlook 2011-2012 warned that Alberta could experience a labour shortage in the coming decade due to the discrepancy between the growth of the labour market of 2.4 per cent and the labour force of 1.9 per cent.
- Mercer (Canada) Limited (Mercer) expected the average annual salary increase for non-unionized employees to range from 3.5 per cent to four per cent for the period of 2013 to 2014. Further, based on 2012 actual salary movement data from a number of ATCO Electric's peers, Mercer predicted that a 3.5 per cent increase was required to maintain competitiveness.

Commission findings

176. Labour inflation rates were not the subject of any significant questioning during this proceeding. Further, interveners did not submit evidence to refute ATCO Electric's labour

[77] Exhibit 226.01, response to AUC-AE-007(c).
[78] Exhibit 51.01.

inflation forecasts. The Commission finds ATCO Electric's labour inflation rate forecast for 2013 and 2014 of 3.5 per cent for both unionized and non-unionized employees to be reasonable and consistent with general trends in the economy and therefore approves a forecast labour inflation rate of 3.5 per cent for each of 2013 and 2014.

5.4.1.2 Inflation rates – contractors – all except direct assigned capital projects

177. ATCO Electric forecast contractor inflation, except for those contractors involved with direct assigned capital projects, to be six per cent for 2013 and 2014, and submitted that this forecast inflation rate is primarily based on actual 2012 tender rates. In the response to information request CCA-AE-029,[79] parts (b), (c) and (e), ATCO Electric provided more information about the derivation of the six per cent figure, the historical relationship between the inflation rates for contractors and CEWA rate increases for the years 2007 to 2011, and the reason why the inflation rates being applied to contractors on non-direct assigned capital projects were different than the inflation rates being applied to contractors on direct assigned capital projects.

Discussion of the issue

178. The CCA argued that the inflation rate allowed for ATCO Electric's transmission function with respect to non-direct assigned capital projects contractor costs should be consistent with that allowed for ATCO Electric's distribution function in Decision 2012-237[80] for PBR. The CCA further argued that contractor rates in the past few years have increased at or about the same rate as labour. The CCA recommended that the non-direct assigned capital projects contractor inflation increases should not exceed 3.5 per cent, the same for labour, for each of the test years.[81]

179. ATCO Electric replied that it was the only party to put evidence on the record regarding contractor escalation and that the six per cent contractor escalation for non-direct assigned capital projects included in its GTA is reasonable because it is based on 2012 tender rates. ATCO Electric also submitted that the Commission had opined in Decision 2011-453[82] that the four per cent escalation approved for AltaLink's 2011-2013 GTA was conservative.

Commission findings

180. Despite the claims from ATCO Electric that the forecast inflation rate is based on 2012 tender rates, based on contracts entered into extending from 2012 to April of 2013, and that a review of the historical average weekly earnings for Alberta utilities for the economic boom years of 2006-2008 indicates an increase of 6.08 per cent in 2006, 6.61 per cent in 2007 and 6.71 per cent in 2008,[83] the Commission does not consider that the evidence submitted in support of the request demonstrates that a forecast of six per cent inflation for these contractor costs is reasonable.

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[79] Exhibit 53.01.
[80] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012.
[81] Exhibit 235.01, CCA argument, paragraph 31.
[82] Decision 2011-453: AltaLink Management Ltd., 2011-2013 General Tariff Application, Application No. 1606895, Proceeding ID No. 1021, November 18, 2011.
[83] As included by ATCO Electric in Exhibit 53.01, the response to CCA-AE-029(b).

181. The Commission finds that ATCO Electric provided no evidence of the types of contracts that were entered into, extending from 2012 into April of 2013, how they were negotiated or who participated in the negotiations. In addition, ATCO Electric provided no detail about the historical weekly earnings percentages it included in the response to information request CCA-AE-029(b), so the Commission is unable to determine whether these percentages are relevant to the issue at hand. Also, despite ATCO Electric's submission with respect to AltaLink in Decision 2011-453, the Commission considers that those findings were based on the record of that proceeding at that time, and such evidence has not been produced in this current proceeding. However, given that this matter was raised, it is worth noting that in Decision 2011-453 the Commission included the following statement:

> The Commission considers it reasonable to assume that general contracted manpower costs will increase at a rate similar to the escalation of total salary and benefit costs for AltaLink staff.[84]

182. The Commission agrees with the CCA that, over the last few years, the inflation rate for contractors has been at or about the same as that for labour, as evidenced by the attachment to the response to information request CCA-AE-029(c). In reviewing this attachment, it is clear that, for each of the years 2009 to 2011, the contractor labour rate increase has been either below or equal to the CEWA labour rate increases. Despite the argument made by ATCO Electric that meaningful comparisons cannot be made between the CEWA rate increases and the contractor labour rate increases,[85] the Commission considers that the comparison shows a trend.

183. The Commission also finds that the explanation provided by ATCO Electric in response to information request CCA-AE-029(e), about why the inflation rate for contractors who work on direct assigned capital projects is forecast to be different than the inflation rate for contractors who work on other capital projects, is not substantiated by any supporting evidence.

184. In Section 5.4.1.3 of this decision, the Commission has approved an inflation rate of four per cent in each of 2013 and 2014 for contractors who work on direct assigned capital projects. As the Commission has not been persuaded by the unsupported assertions of ATCO Electric that the Commission should ignore the trend evidence in favour of imposing a six per cent inflation rate for contract labour, the Commission finds that an inflation rate of four per cent in each of 2013 and 2014 is reasonable to apply to contractors who work on projects other than direct assigned capital projects.

185. While the four per cent inflation rate for contractors is greater than the 3.5 per cent labour inflation rate in each of 2013 and 2014 approved by the Commission in Section 5.4.1.1 of this decision, the Commission has increased the inflation rate in recognition that contractor labour rates can be more volatile and sensitive to labour market supply and demand than the more expansive pool of full time labour personnel. The Commission directs ATCO Electric, in the compliance filing, to use an inflation rate of four per cent in each of 2013 and 2014 for contractor labour for contractors who work on projects other than direct assigned capital projects.

[84] Decision 2011-453, paragraph 135.
[85] As argued by ATCO Electric in Exhibit 53.01, the response to CCA-AE-029(c).

5.4.1.3 Inflation rates – contractors – direct assigned capital projects

186. ATCO Electric forecast inflation of four per cent in each of 2013 and 2014 for contractors working on direct assigned capital projects. In response to information request CCA-AE-029(e),[86] ATCO Electric provided reasons why the forecast inflation rate for contractors working on direct assigned capital projects was different than that for contractors who were not working on direct assigned capital projects. There were no recommendations submitted by interveners during the course of the proceeding to change the forecast inflation rate for contractors working on direct assigned capital projects.

Commission findings

187. The Commission considers the forecast inflation rate of four per cent in each of 2013 and 2014 to be reasonable. In addition, both ATCO Electric and customers are protected from any variances between the actual inflation rates and the forecast inflation rates for this area by the Commission's continued approval of the direct assigned capital projects deferral account, which is discussed in Section 5.1.4 of this decision. Consequently, the Commission approves the forecast inflation rates for 2013 and 2014 for contractors who work on direct assigned capital projects at four per cent in each year.

5.4.1.4 Inflation rates – contractor escalation – direct assigned capital projects

188. In addition to the inflation rate for contractors working on direct assigned capital projects (as discussed in Section 5.4.1.3 of this decision), ATCO Electric requested a 25 per cent escalation in construction costs to reflect cost increases associated with contractors who are currently working at or near capacity, and it filed an internally prepared Construction Cost Escalator Study (CCES) in support of this request.[87] It answered a number of information requests[88] related to this area and the issue was examined during the oral hearing. Intervener evidence on this topic was submitted by the ADC and the RPG and subsequent rebuttal evidence was filed by ATCO Electric. ATCO Electric provided more detailed information about the CCES in response to information request ADC-AE-080,[89] and more details about how the 25 per cent figure was arrived at was provided in response to information request CCA-AE-032(e).[90]

189. ATCO Electric submitted that the AESO's 2012 long-term transmission plan forecasts that sustained oil prices will increase the demand for skilled labour in Alberta, resulting in labour shortages, which will have cost implications for construction of transmission projects as they often compete with the oil industry. ATCO Electric added that its past experience with a heated provincial economy and the ensuing labour market shortages is that construction costs can escalate beyond the base inflation rate, and stated that for this reason it analyzed bid trend data from 2009 to 2011 to determine whether there was evidentiary support for a construction costs escalation factor. ATCO Electric indicated that this analysis, which is contained in the CCES, demonstrates that fewer tender responses create exposure to increased bids not ordinarily seen in a more competitive market and added that for this reason, a one-time escalation factor of

[86] Exhibit 53.01.
[87] Exhibit 1, application, Section 10, Attachment 2.
[88] Exhibit 50.01, response to AUC-AE-022; Exhibit 52.01, response to ADC-AE-080; Exhibit 53.01, response to CCA-AE-032; Exhibit 54.01, response to IPCAA-AE-027, IPCAA-AE-028, IPCAA-AE-029 and IPCAA-AE-030.
[89] Exhibit 52.01.
[90] Exhibit 53.01.

25 per cent had been added to forecasted construction costs for all direct assigned capital projects for the test period, excluding the EATL project, the HRTD program and the NETD program.

Discussion of the issue

190. The RPG submitted a detailed critique of the CCES in its evidence[91] and ATCO Electric provided its response in rebuttal evidence.[92]

191. The RPG submitted that ATCO Electric's requested 25 per cent escalator is based on findings in ATCO Electric's CCES, which is supported by a spreadsheet model. The RPG further submitted that it had identified, in its evidence, a number of flaws with the CCES and the supporting spreadsheet model which ATCO Electric's rebuttal evidence failed to address. It argued that both the CCES and the supporting spreadsheet model should be rejected.

192. The RPG reiterated its concern that ATCO Electric's tendering practices, and specifically the clustering of tenders, could be contributing to the pricing pressure alleged by ATCO Electric. The RPG submitted that ATCO Electric's testimony has only heightened the RPG's concerns about ATCO Electric's tendering and planning practices.

193. The RPG submitted that to the extent that there is an imbalance between resources and workload, it is preferable to address these fundamental issues through work smoothing and project prioritization. The RPG further submitted that "throwing dollars at the issue is inefficient, unreasonable, and contrary to the public interest."[93]

194. The RPG further argued that publicly accepting and directing a 29 per cent[94] construction cost increase will only incent contractors to inflate their prices because they understand that ATCO Electric is expecting such an increase. This increase, the RPG submitted, "is more likely to be a self-fulfilling prophecy than a reflection of a reasonable forecast."[95] The RPG further argued that not allowing the added 25 per cent construction cost escalation will provide an incentive for ATCO Electric to plan and tender its contracts as efficiently as possible.

195. The ADC argued that the additional 25 per cent escalator is speculative because it requires that a series of assumptions hold. More specifically, the ADC explained that the reasoning for the 25 per cent escalator rests on the assumption that sustained oil prices would cause labour shortages in the oil industry, which would consequently affect the supply of labour for transmission construction. In addition, the escalator assumes that a trend analysis based on bids from 2009 to 2011 can reasonably forecast the transmission construction labour market in 2013 and 2014.

196. The ADC further argued that even though AltaLink Management Ltd. will generally experience the same contractor cost pressures as ATCO Electric, AltaLink has not requested an additional contractor cost escalator in its own 2013-2014 GTA. Finally, it submitted that if ATCO Electric actually experiences the cost increase, it will have the safety net of deferral accounting to ensure it recovers the cost.

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91 Exhibit 103.01, Section 8, pages 38-41; Section 15, pages 86-100.
92 Exhibit 116.01, pages 22-26, page 57.
93 Exhibit 238.01, RPG argument, paragraph 21.
94 This is comprised of the 25 per cent escalator, and the four per cent contractor inflation rate.
95 Exhibit 238.01, RPG argument, paragraph 22.

197. The UCA submitted that the total forecast amount for ATCO Electric's direct assigned capital projects include both contingency amounts built into each project estimate and a 25 per cent escalation factor for contractor fees for direct assigned capital projects. The UCA opposed the use of both contingency estimates and the 25 per cent escalator for the following reasons:[96]

- Deferral accounts transfer the risk of any cost overruns to customers.
- In the case of overages, current customers pay for costs that will be credited to future customers via the direct assigned capital projects deferral account.
- The escalator relief ATCO Electric applied for is predicated on competitive tendering as a cost-causing process, rather than a mechanism designed to ensure cost competitiveness.

198. The UCA submitted that ATCO Electric rationalized the 25 per cent escalation factor as a response to a decline in compliant bids from 2008 to 2011. The UCA argued, however, that under cross-examination, Mr. Kostyk, a witness for ATCO Electric, failed to justify using the bid compliance rates from the 2008 to 2011 period to forecast compliance rates for the 2013 and 2014 test period. The UCA further argued that Mr. Kostyk also failed to link the compliance rate, cost escalations and blanket cost escalator to an established industry procurement practice, other than ATCO Electric's internal expertise.

199. The UCA further submitted that Mr. Kostyk did not recognize that a 25 per cent escalation factor would likely lead to bid inflation. The UCA argued that Mr. Kostyk's suggestion that competitive pressure would prevent knowledge of the escalator from leading to inflated bids is contrary to ATCO Electric's reasoning for the escalator in the first place, which was a lack of competitive pressure.

200. The UCA stated that competitive tendering is a mechanism that ensures or reduces properly prepared cost estimates. The UCA expressed its view that ATCO Electric appears to argue that competitive tendering is an unpredictable cost escalator in Alberta. It recommended that the 25 per cent escalator and direct assigned capital projects contingency amounts be denied and argued that their removal will not harm ATCO Electric, whereas their inclusion harms customers by charging them more now, creating intergenerational inequity, and puts off addressing the core issue of failing tenders.

201. ATCO Electric submitted that it requested the 25 per cent contractor construction cost escalation factor to cope with the forecasted cost increases and shortage of contractor resources. In response to interveners' arguments that ATCO Electric's practice of clustering bids is the source of increased cost pressure, ATCO Electric submitted that it schedules work in accordance with multiple constraints, including a narrow construction season dictated by winter only construction areas of muskeg, project in service dates, receipt of permits and licenses, and customer demands. It further submitted that staggering tenders would not assist in reducing the competitive pressures because these are driven by the actual construction work and not when the tender is issued.

202. ATCO Electric argued that it is very difficult for it to assess precisely how AltaLink has chosen to handle AltaLink's forecasted cost increases. ATCO Electric added that it understands,

[96] Exhibit 237.02, UCA argument, paragraph 9.

however, that it is built into the contingency amounts. It submitted that it has gathered significant information on the cost pressures it is facing in completing its capital projects during the test period, is attempting to put forward the best forecast possible based on the information available, and requested that the contractor cost escalation factor be approved as requested.

Commission findings

203. Although it recognizes ATCO Electric's concerns with a heated provincial economy, the Commission agrees with interveners that a 25 per cent escalation factor may introduce a number of unintended consequences that would outweigh any of its benefits. More specifically, the use of an escalation factor could lead to bid inflation, introduce intergenerational inequities, and reduce ATCO Electric's incentive to improve its tendering process.

204. In response to a Commission undertaking,[97] ATCO Electric provided details of the dollar amounts included in this request for a 25 per cent escalation factor. In that undertaking response the resulting amounts are shown as $34.7 million in 2013 and $42.0 million in 2014.[98] These amounts were also calculated by the ADC in its evidence.[99] The ADC further submitted that the resulting revenue requirement impact of disallowing the amounts of $34.7 million and $42.0 million would be $1.3 million in 2013 and $2.9 million in 2014. The forecast revenue requirements included in the omissions and updates filing are $536.3 million for 2013 and $662.7 million for 2014. The $1.3 million represents approximately 0.2 per cent of the 2013 forecast revenue requirement and the $2.9 million represents 0.4 per cent of the 2014 forecast revenue requirement. The Commission considers that neither of these percentages is significant and that ATCO Electric has not demonstrated that it is reasonable to include this escalation in its forecast.

205. Further, an escalation factor is unnecessary because direct assigned capital projects are already subject to deferral account treatment. The Commission consequently denies ATCO Electric's request for a 25 per cent contractor escalation factor for its direct assigned capital projects and directs ATCO Electric to reflect this finding in the compliance filing.

206. The UCA made a recommendation relating to the contingency amounts that ATCO Electric included in the forecast for direct assigned capital projects. The Commission has addressed this issue in Section 11.9.1 of this decision.

5.4.1.5 Inflation rates – other

207. ATCO Electric forecast cost increases of 2.2 per cent and 2.1 per cent for the years 2013 and 2014 respectively for other inflation. ATCO Electric submitted that these forecasted rates are based on an average of Alberta Consumer Price Index (CPI) forecast rates from a number of government and financial institutions for the 2013 and 2014 test years. In response to information request ADC-AE-114(a) and (b)[100] it provided more detailed information about the calculation of the forecast amounts and provided copies of the source material, with the exception of one.

[97] Exhibit 202.01.
[98] Exhibit 202.01, line 22.
[99] Exhibit 88.03, evidence of the ADC, page 11, lines 3-4.
[100] Exhibit 52.01.

Discussion of the issue

208. The ADC questioned the inclusion of an amount for inflation on the non-labour O&M costs of ATCO Electric for the 2013 and 2014 test period, submitted that expense fluctuations between years can increase or decrease for several reasons and submitted that the occurrence of these events could affect the actual level of inflation experienced. It added that the effects of inflation cannot be addressed in isolation, but only through a thorough review of the total operations of ATCO Electric. The ADC submitted more information about this issue in response to information request AUC-ADC-003[101] and recommended that the Commission disallow the requested inflation factors on the non-labour O&M costs of ATCO Electric for the 2013 and 2014 test periods.

209. ATCO Electric stated that it is a well-accepted fact that the business environment within which Alberta utilities operate is under Alberta-specific inflationary cost pressures. It added that the Commission has recognized the appropriateness of including a general inflation factor based on the Alberta CPI as part of the overall forecasted costs, and referenced paragraph 133 of Decision 2011-453 on the AltaLink Management Ltd. 2011-2013 GTA as evidence of that recognition. ATCO Electric also referenced paragraph 209 of Decision 2012-237 on the rate regulation initiative where it claimed the Commission further acknowledged the impact of Alberta CPI inflation on future costs.

210. While the ADC acknowledged that inflation is a primary cause for expense escalation, it noted that aggressive management can mitigate this expense effect with effective cost management. It stated that ATCO Electric's GTA forecast is based on an implicit assumption that inflation impacts on expenses cannot be addressed and added that ATCO Electric had not accurately demonstrated that productivity offsets would not fully absorb any escalation in O&M costs created by inflation.

211. In reply, ATCO Electric argued that there is no evidence on the record to support a correlation between non-labour O&M inflation rates and productivity. It further argued that because historic and forecast productivity gains are already imbedded in its forecast, consequently disallowing the inflation factor would be a measure over and above the efficiency gains already included in the forecast.

Commission findings

212. No issues were raised by any parties with respect to the calculations made or the sources used by ATCO Electric for the proposed rates for other inflation. The ADC's recommendation was with regard to the total disallowance of inflation for non-labour O&M costs. The Commission considers that the ADC has not provided sufficient justification to support a total disallowance of other inflation. To the contrary, the ADC has acknowledged that inflation is a primary cause of expense escalation. The Commission considers that there are inflationary pressures on the non-labour O&M costs of ATCO Electric's transmission function and, if the Commission does not permit any aspect of these inflationary pressures to be reflected in the revenue requirements, it could quite possibly limit ATCO Electric's reasonable opportunity to recover its prudently incurred non-labour O&M costs.

213. While the ADC stated that ATCO Electric's GTA forecast is based on an implicit assumption that inflation impacts on expense cannot be addressed, the Commission considers

[101] Exhibit 107.01.

that the ADC's recommendation takes the opposite extreme position. If the Commission were to eliminate the entire inflation rate forecast for non-labour O&M costs, this would assume that ATCO Electric would be able to mitigate this entire inflation effect. The Commission finds that the ADC has not demonstrated this to be the case.

214. An analysis of the variances between the forecast approved and actual non-labour O&M costs for ATCO Electric would have been helpful in segregating out the impact that inflation, as well as productivity/efficiency gains, had in these variances and would demonstrate ATCO Electric's ability to mitigate the effects of inflation on these costs. However, the ADC did not perform any such analysis with respect to any of the non-labour O&M costs.

215. In an exchange with Mr. Meyer, an ADC witness, who was questioned by Commission counsel about whether it would be easier to impose an efficiency factor as opposed to going through and trying to identify the impacts of inflation versus technological advancement, Mr. Meyer stated:

> Q. Okay. As an alternative to going through and trying to identify the impacts of inflation versus technological advancement, which is what your response here is, would ADC think it might be just as easy just to impose an efficiency factor?
> A. MR. MEYER: Well, you know, obviously that's been considered, but when I looked at -- if I looked at an IR response CCA-AE -- I believe it's 2, and in there, I found a statement that says: (as read)
> "The subject of productivity measurement in the context of an electric transmission utility is extraordinarily complex and has been the subject of much debate in various regulatory proceedings over the years."
> So, you know, ATCO doesn't have any problems telling us how difficult it is to measure a productivity adjustment in a case, but yet once they just come in and give a -- have an inflation factor applied, which I believe -- and I discussed in this IR response, is also very difficult to measure and to show the impact.[102]

216. The Commission agrees that the subject of productivity measurement in the context of an electric transmission utility is a complex undertaking. This whole area of productivity measurement was examined in detail during the Commissions' rate regulation initiative PBR, as evidenced by Section 6 of Decision 2012-237. The Commission considers that such a productivity measurement for the electric transmission utility would also require considerable resources to complete. Without the benefit of such a productivity measurement for transmission, the Commission is not prepared to impose any kind of efficiency factor in this application.

217. Mr. Meyer, in the quote above, suggests that it is also very difficult to measure and show the impact of inflation. However, without the benefit of such a measurement, the Commission considers that it has no basis upon which to completely eliminate the other inflation rates for

[102] Transcript, Volume 7, page 1412, lines 3-23.

non-labour O&M costs, especially considering that it has previously approved the inclusion of inflation rates for other non-labour costs of ATCO Electric.[103]

218. For the reasons set out in this section, the Commission rejects the recommendation of the ADC to remove the other inflation rates for non-labour O&M costs. Further, the Commission finds that ATCO Electric's proposed other inflation rates forecasts are in line with current market conditions. The Commission approves ATCO Electric's other inflation rates forecasts of 2.2 per cent in 2013 and 2.1 per cent in 2014.

5.4.2 Vacancy rates

219. ATCO Electric advised that the following vacancy rates were used in the preparation of the forecast for the 2013-2014 test period.

Table 6. Assumptions – vacancy rates[104]

	2013 (%)	2014 (%)
Transmission direct O&M	6.0	6.0
Other O&M	3.5	3.5
Capital	5.0	5.0

220. Based on the actual direct transmission labour vacancy rates experienced over the past several years, current staffing levels relative to planned staff additions over the forecast and test periods, and the directions in Decision 2011-134, which stipulated the use of a four year historical average, ATCO Electric forecast a transmission direct O&M vacancy rate of six per cent. It submitted that following a similar review, it forecast an average vacancy rate of 3.5 per cent for all other staff charged to O&M.

221. ATCO Electric further submitted that the forecast vacancy rate for staff charging to capital was also based on a review of the actual vacancy rates experienced over the past several years as well as current staffing levels relative to planned additions over the forecasted period. Based on this review, it forecast a vacancy rate of five per cent for staff charged to capital.

222. In response to information request ADC-AE-047,[105] ATCO Electric provided the actual vacancy rates for these three areas for each of the years 2003 to 2011. During the oral hearing in response to questioning from Commission counsel, Mr. McNabb, an ATCO Electric witness, advised that the 3.5 per cent vacancy rate was applied to all corporate labour employees, both capital and O&M.[106]

Discussion of the issue

223. The CCA raised an issue with respect to the forecast vacancy rates for corporate labour, submitting that compared with GTA forecasts, ATCO Electric's historical vacancy rates have been significantly higher. More specifically, using information from the response to information request CCA-AE-040(a), the CCA calculated that the average forecast variance percentage over the last three GTAs was 8.1 per cent. It recommended that the vacancy rate used to calculate the

[103] Paragraph 272 of Decision 2011-134.
[104] Exhibit 1, application, Section 1, paragraph 42.
[105] Exhibit 52.01.
[106] Transcript, Volume 3, page 509, lines 10-21.

2012, 2013 and 2014 corporate labour costs be increased to 8.1 per cent to reflect the vacancy rates actually experienced by ATCO Electric.

224. ATCO Electric replied that the analysis provided by the CCA in support of its recommendation was flawed. More specifically, it argued that the 8.1 per cent figure calculated by the CCA purports to demonstrate an average forecast vacancy rate variance. However, the forecasted number of FTEs used in the calculation already factors in the vacancy rate and, therefore, is not an appropriate base comparator for calculating an average forecast vacancy rate variance. ATCO Electric further submitted that the CCA's calculation uses data applicable to 2012 net additions three times and 2011 net additions twice. ATCO Electric argued that this is not an appropriate calculation because the CCA derives an average vacancy rate using the same information for multiple years.[107]

225. ATCO Electric also submitted that its nine-year average vacancy rate for corporate O&M labour, as evidenced in the response to information request ADC-AE-047, is 3.9 per cent, which is well within the range of the applied-for 3.5 per cent forecast vacancy rate for the test period. It further submitted that, as of November 30, 2012, it had 142 corporate FTEs and argued that this statistic matches and supports its 3.5 per cent vacancy rate forecast for the test period because its FTE forecast for December 31, 2012 was 147 FTEs.

Commission findings

226. The Commission has examined the calculation submitted by the CCA in paragraph 34 of its argument that is the basis for the CCA's recommended vacancy rate for corporate labour. While the CCA claims that its calculations show the average forecast variance percent over three GTAs, the Commission notes that there is only complete information for 2010 and 2011, and that the information for 2012 is not complete. The CCA's calculation is reproduced in the following table:

[107] Exhibit 246.01, ATCO Electric reply argument, paragraph 26.

Table 7. Comparison of forecast to actual total corporate O&M manpower additions to complement[108]

		Permanent and temporary			
		Forecast # of FTEs	Actual # of FTEs	Variance # of FTEs	Variance %
Reference / notes	**2009 – 2010 GTA:**				
(2008 ending balance)	2009 Beginning	66.5	71.5	(5.0)	
FC 2009-2010 GTA	2009 Net additions	15.2	7.6	7.6	
FC 2009-2010 GTA	2010 Net additions	5.6	2.9	2.7	
		87.3	82.0	5.3	6.1
	2011 – 2012 GTA:				
(2009 ending balance)	2010 Beginning	81.7	79.1	2.6	
FC 2009-2010 GTA compliance	2010 Net additions	5.6	2.9	2.7	
FC 2011-2012 GTA compliance	2011 Net additions	8.5	5.0	3.5	
FC 2011-2012 GTA compliance	2012 Net additions	2.1	0.0	0.0	
		97.9	87.0	8.8	9.0
	2013 - 2014 GTA:				
	2010 Beginning	81.7	79.1	2.6	
2009 – 2010 GTA compliance	2010 Net additions	5.6	2.9	2.7	
2011 – 2012 GTA compliance	2011 Net additions	8.5	5.0	3.5	
		95.8	87.0	8.8	9.2
Average forecast variance per cent over three GTAs					8.1

227. The Commission considers that the 6.1 per cent variance represents the figure for 2010 and the 9.2 per cent represents the figure for 2011. The Commission has no concern with the accuracy of the calculation of these figures. However, in the calculation of the nine per cent variance related to 2012, there is information missing, namely the actual FTEs for 2012. While this figure is not known, the forecast corporate O&M adjusted complement for 2012 of 98.2 FTEs included as part of the revenue requirement supporting schedules[109] submitted in conjunction with the omissions and updates filing is a good proxy for what the 2012 actual figure will be, especially considering that the omissions and updates filing was submitted on November 20, 2012. If the 98.2 FTE figure is used in place of the 87.0 FTE figure for 2012, the resulting variance percentage for 2012 is (0.3). This results in an average forecast variance figure over the three years of five per cent, which is much lower than the 8.1 per cent figure the CCA calculated.

228. In addition, while the CCA recommended that the 8.1 per cent be applied to the entire corporate labour forecast, this does not recognize that corporate labour is split between O&M and capital. Although ATCO Electric acknowledged that it used a 3.5 per cent vacancy rate for all corporate labour in the forecasts for 2013 and 2014, the Commission considers that, in assessing the corporate labour vacancy forecasting accuracy of ATCO Electric, it is important to consider both the O&M and capital pieces. The Commission has calculated this forecasting accuracy in the following table.

[108] Exhibit 235.01, CCA argument, page 13.
[109] Exhibit 188.02, Schedule 25-5, line 18.

Table 8. Comparison of forecast to actual total corporate manpower[110]

	Permanent and temporary			
	Forecast # of FTEs	**Actual # of FTEs**	**Variance # of FTEs**	**Variance %**
2010	106.9	109.8	(2.9)	(2.7)
2011	122.8	115.1	7.7	6.3
2012	125.8	132.2	(6.4)	(5.1)
3-year average				(0.5)

229. On an overall basis, ATCO Electric's forecasting accuracy with respect to corporate FTEs over the years 2010, 2011 and 2012 has been good. No reasons have been presented during the course of the proceeding that would cast doubt on the ability of ATCO Electric to continue to forecast reasonably over the 2013-2014 test period. The Commission finds that the 3.5 per cent vacancy rate ATCO Electric has forecast for corporate labour over the test period is reasonable, given the average vacancy rate over the past three years as shown in Table 8 of this decision. Consequently the Commission rejects the CCA's recommendation to increase the vacancy rate to 8.1 per cent and approves the 3.5 per cent vacancy rate for corporate labour for 2013 and 2014 as applied for by ATCO Electric.

6 Fuel

230. Background information about the requirement for fuel is included in Section 5.1.1 of this decision.

231. ATCO Electric forecasts fuel costs for its isolated communities and telecommunication sites based on natural gas prices, crude oil prices (which include transportation costs) and foreign exchange rates, using information from a variety of sources which included Gilbert Laustsen Jung Associates Ltd, Sproule Associates Ltd., the government of Alberta, Global Insight, the United States Energy Information Administration and various Canadian chartered banks.

232. Forecast gas volumes were determined by applying the five-year average annual heat rate for the plant (based on historic generation and consumption data), to the forecast generation output.

233. Forecast diesel volumes were determined at each plant by applying the average annual heat rate for the plant to the forecast generation output. The load forecast was based on historic trends and discussions with large load customers, and the average annual heat rate was based on historic generation and fuel consumption data or manufacturer date at new telecom sites.

234. In the omissions and updates filing, ATCO Electric incorporated an adjustment to the forecast fuel costs. This adjustment, which was a reduction in forecast fuel costs of $0.2 million in each of 2013 and 2014, was identified by ATCO Electric as being related to an error in its

[110] Source: Exhibit 1, application, Section 31, Attachment 5, Schedule 25-5, page 122 of 174, page 113 of 174, line 19 on each page; with the exception of the 2012 actual amount which comes from Exhibit 188.02, Schedule 25-5, line 21. Exhibit 188.02 is the forecast update included in the supporting revenue requirement schedules filed in conjunction with the omissions and updates filing.

average heat rate by plant calculation. The resulting fuel cost forecasts are now $6.8 million for 2013 and $7.2 million for 2014.

235. During cross-examination by the CCA, an ATCO Electric witness provided an update of forecast fuel prices as of October 27, 2012, and indicated that if the forecast fuel prices as of October 27, 2012, were used, the resulting fuel costs forecast would be $6.3 million for 2013 and $6.8 million for 2014.[111]

Discussion of the issue

236. The ADC proposed that ATCO Electric's forecast fuel expense be reduced based on a review of historical actual fuel costs from 2009 through 2011. While the ADC acknowledged that projecting commodity prices can be difficult, it indicated that ATCO Electric's projected increase in fuel costs for 2013 and 2014 does not appear to compare reasonably to the actual increases experienced over the last few years. The ADC recommended that the forecast amount for fuel costs in each of 2013 and 2014 be $6.3 million and added that ATCO Electric has a deferral account for fuel costs which eliminates any forecast risk.

237. The CCA submitted that the resulting fuel costs forecast provided by ATCO Electric during the oral hearing did not appear to include the adjustment reflected in the omissions and updates filing and consequently recommended that the update provided be reduced by $0.2 million in each year to reflect the adjustment made in the omissions and updates filing. This would result in a forecast of $6.1 million for 2013 and $6.6 million in 2014.

238. ATCO Electric clarified that the fuel cost forecasts provided during the hearing already reflected the adjustment made in the omissions and updates filing and that the CCA's recommendation would double count the original correction. It also submitted that it is not necessary for the Commission to reduce the fuel costs forecast to reflect the update provided during the oral hearing, and maintained that fuel costs are volatile and have no doubt changed again since the updated pricing information was provided during the oral hearing.

239. ATCO Electric indicated that future commodity prices are dictated by several factors such as supply and demand, government trade policies, changing currency valuations, and price speculation among others, and that none of these factors can be accurately forecasted by simply looking at historical commodity prices.

240. The ADC disputed ATCO Electric's claim that the increase in fuel costs is primarily due to increased fuel prices. The ADC added that the projected level of generation also has an impact on the forecast fuel costs and that the forecast level of generation at the gas run plants for 2013 and 2014 was experienced by ATCO Electric during the 2010 to 2012 time frame. It stated that the forecast level of generation at the diesel run plants for 2013 was only exceeded in 2010 and the level projected for 2014 has never been experienced.

Commission findings

241. The Commission will first address the claim made by the CCA that the update provided by ATCO Electric during the oral hearing appears to exclude the adjustment reflected in the omissions and updates filing. In the omissions and updates filing, ATCO Electric included a

[111] Transcript, Volume 2, page 324, lines 19-25; page 325, lines 1-13.

schedule[112] that detailed the updated fuel cost forecasts of $6.8 million and $7.2 million included in the omissions and updates filing. While this schedule was not complete, with working formulas, the calculations are relatively easy to follow. When the updated fuel prices provided by ATCO Electric are included in the schedule that was provided as part of the omissions and updates filing and the resulting calculations are made, it is clear that the resulting $6.3 million and $6.8 million figures include the adjustment reflected in the omissions and updates filing. Consequently, the Commission rejects the CCA's claim.

242. In Section 5.1.1 of this decision, the Commission examined the request from ATCO Electric for deferral treatment with respect to fuel costs and prepared a table[113] (Table 3) which detailed the actual and forecast fuel costs of ATCO Electric for 2009-2012. From the information in Table 3 it is clear that, for each of the years 2009, 2010, and 2011, ATCO Electric's actual fuel costs were substantially lower than the approved forecast amounts. This trend is also forecast to continue in 2012 based on the figures for 2012 in Table 3 of this decision.

243. Based on the information included in Table 3 of this decision, the Commission agrees with the ADC that the actual annual fuel costs over the period 2009 to 2011 is approximately $6.3 million, and that the latest forecast of fuel costs for 2012 is also $6.3 million. This is despite the approved annual forecast amounts for this period ranging from $8.3 million for 2011 to $9.6 million for 2010. The Commission has included some variance analysis around the $6.3 million amount for each of 2013 and 2014 in paragraph 43 of this decision. Based on the actual fuel cost levels for the years 2009 to 2012, ATCO Electric's history over the last four years of over-forecasting the fuel costs, as well as the variance analysis included in paragraph 43 of this decision, the Commission finds that a reasonable forecast for the years 2013 and 2014 would be $6.3 million for each year and directs ATCO Electric, in the compliance filing, to include fuel costs of $6.3 million for 2013 and $6.3 million for 2014.

7 Operating costs

244. The forecast operating costs for ATCO Electric's transmission function are comprised of a number of different categories. The direct O&M category includes the costs for employees who work exclusively for the transmission function. The isolated generation category, the general category and the common operations category represent ATCO Electric's transmission function's allocated amount of O&M costs that are incurred on behalf of the entire company. The administrative and general (A&G) category is also an allocated amount. Taxes other than income taxes consist of property taxes. Farms, irrigation operating costs are amounts incurred by ATCO Electric's distribution function. However, because these farms, irrigation operating costs are required to be paid by the Independent System Operator (ISO) (currently the AESO) they are included as part of ATCO Electric's transmission revenue requirement, because all of the transmission function's revenue requirement is paid by the AESO.

245. In the revenue requirement supporting schedules filed in conjunction with the omissions and updates filing, ATCO Electric included the following with respect to operating costs.

[112] Exhibit 117.05.
[113] Table 3, in paragraph 42.

Table 9. Operating costs[114]

	2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
	($ million)				
Direct O&M	30.8	38.0	43.7	43.2	48.5
Allocated share of isolated generation O&M	6.4	5.8	6.5	6.9	7.2
Allocated share of general O&M	3.9	4.3	4.9	6.3	6.9
Allocated share of common operations O&M	2.3	2.3	4.0	4.7	5.0
Allocated share of A&G	15.2	20.0	23.1	27.7	29.2
Taxes other than income	18.3	21.1	23.0	30.0	37.5
Farms, irrigation	0.9	1.1	1.1	1.2	1.3
Total	77.8	92.6	106.3	120.0	135.6
Increase from previous year ($)		$14.8	$13.7	$13.7	$15.6
Increase from previous year (%)		19.0%	14.8%	12.9%	13.0%

246. ATCO Electric stated that the primary drivers for the increases in operating costs are:

- an increase in taxes other than income taxes resulting from capital additions
- an increase in its labour force associated with managing a growing asset base and the requirement to support new industry requirements such as cyber security and Alberta Reliability Standards
- increased buildings operations costs associated with new buildings
- increased costs for vegetation management
- increased costs for VPP
- inflation

7.1 Direct operation and maintenance costs

247. ATCO Electric owns and operates interconnected transmission facilities in northern and east central Alberta, covering 62.5 per cent of the province. As of March 2012, its direct O&M facilities include 157 substations, approximately 10,459 kilometres (km) of transmission line and a systems operations centre. The substation facilities incorporate 221 power transformers, 973 circuit breakers and circuit switchers, and associated apparatus such as support structures, instrument transformers, high voltage switches, and protection relays and control devices.

248. The direct O&M comprises 120 FTE positions. This staff is responsible for engineering, planning and carrying out the O&M of interconnected transmission facilities, and operates from a central office and nine strategically located field service depots including main offices in Grande Prairie and Vegreville. Staff are trained and qualified as professional engineers, electrical technologists, journeyman linemen, forestry professionals, forestry technicians, transmission system operators, process systems support staff, and administrators/clerks.

[114] Source: Exhibit 188.02, Schedule 5-1.

249. ATCO Electric included the following information about the forecast growth of its transmission system over the test period.

Table 10. Transmission system growth forecast[115]

	2011 actuals	2013 forecast	2014 forecast	% increase 2011-2014
Total number of substations	157	165	193	22.9%
Power transformers	221	229	260	17.6%
Circuit breakers and circuit switchers	973	1,030	1,222	25.6%
Transmission line length (km)	10,459	10,654	11,305	8.1%

250. In the revenue requirement supporting schedules filed in conjunction with the omissions and updates filing, ATCO Electric included the following with respect to direct O&M costs.

Table 11. Direct operation and maintenance costs[116]

	2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
	($ million)				
Supervision and engineering	3.0	3.2	3.8	4.6	5.3
Control centre operations	2.1	2.4	3.4	3.8	4.4
Station equipment expenses	7.0	7.1	7.3	8.6	9.6
Overhead lines expense and operation maintenance	3.8	3.6	3.8	4.0	4.9
Miscellaneous transmission expense	7.2	12.1	14.7	8.7	9.7
Annual structure payments	1.9	2.6	3.1	4.0	4.4
Vegetation management	4.3	4.9	5.1	6.1	6.3
IT support	1.6	2.3	2.6	3.3	3.8
Total	30.9	38.2	43.8	43.1	48.4
Increase from previous year ($)		$7.3	$5.6	($0.7)	$5.3
Increase from previous year (%)		23.6%	14.7%	(1.6%)	12.3%

Note: Totals on this table may be different from those in Table 9 due to rounding.

251. As discussed below, the CCA and the ADC made recommendations in a number of areas relating to direct O&M costs.

7.1.1 Health and safety standards

252. The CCA expressed a concern with a statement made by ATCO Electric in the application that "ATCO Electric continues to strive for world class health and safety performance." The CCA wondered if ATCO Electric had to pursue world class safety standards to attain statistics similar to the Canadian Electricity Association (CEA) and questioned whether this attempt to comply with some undefined notion of "world class" standards may be resulting in additional costs to customers, particularly if, by employing what appears to be higher standards than required by the safety laws governing Alberta employees, ATCO Electric's safety performance statistics are comparable to those of the CEA.

[115] Source: Exhibit 1, application, Section 5, paragraph 87.
[116] Source: Exhibit 188.02, Schedule 5-1.

253. The CCA argued that ATCO Electric continues to strive for world class health and safety performance without full knowledge of the practices of other transmission facility owners (TFOs) in Alberta, and submitted that the onus is on ATCO Electric to provide adequate and sufficient evidence that its health and safety standards and practices, and associated costs are similar to those of its peers. The CCA recommended that the Commission direct ATCO Electric to provide, at its next transmission GTA, an assessment of whether its health and safety standards and practices, and associated costs, are similar to those of its peers.

254. ATCO Electric argued that the information that the CCA sought does not exist in a readily accessible format, or at all, and that the undertaking of such an exercise is questionable given the time and cost that would be involved. ATCO Electric added that this would appear to entail an analysis of other utilities' internal procedures and an incremental cost analysis which would be difficult to undertake. ATCO Electric indicated that it is not a simple question of identifying health and safety standards to isolate the costs of activities undertaken related to these standards. ATCO Electric stated that managing work and the transmission system safely is a consideration in all activities and decisions undertaken and as such, isolating all activities related to health and safety performance, or the amount of time dedicated by employees, is an impossible task.

Commission findings

255. The Commission considers that the term "world class health and safety performance" as used by ATCO Electric in its application is essentially a generic term and does not relate to any particular set of measurable health and safety standards that would be adopted by utilities worldwide. The only information provided during the course of the proceeding with respect to measurable safety statistics was provided in paragraph 86 of the application.[117] These safety statistics were those for all injury frequency and vehicle incident frequency.

256. Comparing ATCO Electric's results in these two safety statistics to the CEA average shows that ATCO Electric's performance is very good in both areas. While it is not known which specific companies make up the CEA average, it is assumed that they constitute peer companies of ATCO Electric. There is no legislated or mandated requirement that ATCO Electric's safety statistics be better than the CEA average. However, there is nothing wrong with ATCO Electric choosing to compare its safety statistics to those of its peers in the CEA.

257. ATCO Electric is not required to have full knowledge of the health and safety practices of the other TFOs in the province, nor the associated costs incurred by these other TFOs. While this knowledge may be beneficial to ATCO Electric, it is the responsibility of ATCO Electric to establish its own health and safety practices. The CCA provided no evidence on acceptable safety standards, or what the associated costs should be, and made no recommendations to disallow costs related to this area of health and safety.

258. The Commission agrees with ATCO Electric that safety is a concern that should permeate the entire company and that it would be difficult to isolate and measure the entire cost associated with this. There is no cost category under the Uniform System of Accounts for health and safety costs. While the Commission considers that it is relatively easy to account for the costs associated with training programs, such as refresher driver training and fall arrest training,

[117] Exhibit 1, application, Section 5, paragraph 86, Table 5.2.

there are other areas where the costs are not so easy to measure, such as a focus on adherence to best practices and improving orientation processes. In addition, it would be difficult to measure the quantifiable benefits of such health and safety efforts.

259. No evidence of imprudence relating to any of the forecast health and safety expenditures of ATCO Electric was raised during the course of the proceeding.

260. On this basis, the Commission rejects the CCA's recommendation that ATCO Electric provide, in its next GTA, an assessment of whether its health and safety standards and practices, and associated costs, are similar to those of the other TFOs. While the overall costs incurred for safety are difficult to quantify, the Commission directs ATCO Electric, in its next GTA, to identify any specific incremental costs that are included for safety, and to make sure these incremental costs are justified.

7.1.2 O&M labour force growth deferral

261. The ADC is concerned with the forecast growth in the labour force for all areas associated with the transmission operations. The ADC submitted that ATCO Electric was forecasting to increase the O&M FTEs by 85 during the 2012-2014 time period.[118] The ADC's concern centered around the connection it made between the capital project activity and the O&M labour force, stating that if ATCO Electric is unable to meet its construction budgets for its capital projects, its forecast O&M labour force, which operates and maintains the capital facilities, will be overstated.

262. The ADC's concern with ATCO Electric's ability to meet its capital construction budgets was in regard to ATCO Electric's ability to achieve its forecast level of growth in FTEs who work on capital projects. The ADC stated that ATCO Electric was projecting to double its capital work force over the 2012 to 2014 period and expressed doubt about ATCO Electric being able to achieve this forecast, considering ATCO Electric's evidence about the existing demand on the available labour force in Canada. The ADC assumed that if these levels of capital FTEs could not be hired, the forecast amount of capital project work would not be achieved.

263. To guard against the overstatement of the labor and fringe costs associated with the forecast O&M labour force, the ADC proposed that a deferral account be established, and recommended that a placeholder be established for the 2013 and 2014 test period that would set the O&M labour force at the 2012 level. With this adjustment, it recommended a reduction of $2.7 million in the revenue requirement for 2013 and a reduction of $5.6 million in the revenue requirement for 2014.[119]

264. ATCO Electric submitted that the notion that increased capital assets drive additional operational requirements only after they go into service is incorrect, and it provided a number of operational activities that it indicated were required before new facilities are energized. It added that the introduction of more complex transmission infrastructure drives additional workload and complexity in all areas of transmission operations, and that training is required for the engineers, technologists and operators working with new equipment. ATCO Electric advised that new

[118] Exhibit 1, application, Section 5, Schedule 5-5.1, page 4 of 4, line 196: 25.5 for O&M, 16.9 for O&M; Schedule 5-5.2, page 3 of 3, line 141: 8.1 for O&M, 20.0 for O&M; Schedule 5-5.3, page 2 of 2, line 84: 4.9 for O&M, 9.7 for O&M. 25.5 +16.9+8.1+20.0+4.9+9.7 = 85.1.

[119] As detailed in Exhibit 211.02 and Exhibit 211.03.

operating manuals, troubleshooting guides, contingency plans and sparing strategies need to be developed, and that system growth is just one area driving an increase in the O&M FTEs.

265. ATCO Electric stated that its forecast O&M FTE additions for 2013 and 2014 are fully achievable based on its recruitment successes in 2012 as well as the continued implementation of the recruitment strategies detailed in the application.

Commission findings

266. The principle issue to be determined is not the placeholder amount, but the approval of the deferral account itself. During questioning Mr. Meyer, a witness for the ADC, indicated that a percentage of the forecast O&M increase could be put in as a placeholder, or potentially the entire amount.[120]

267. The Commission understands the ADC's concern that O&M FTEs, which are linked to the capital project forecast, could be overstated given the uncertainty associated with the capital projects forecast. However, this concern has to be weighed against whether the amounts subject to deferral treatment are material and the reasons for the establishment of the deferral account. During the oral hearing, Mr. Meyer stated that 70 per cent or more of the O&M FTEs to be hired during the test period are directly related to capital growth. However, the Commission finds that the ADC has not demonstrated whether the capital growth referred to by the ADC is entirely for capital growth during the 2013 and 2014 test period. The capital growth may include capital growth from previous years. If this is the case, that capital growth has already occurred and ATCO Electric is required to operate these new facilities.

268. In addition, the Commission finds that the ADC has not quantified or identified what the relationship is between the level of capital growth and the resulting O&M FTEs. For example, if the actual capital growth in the test period was 75 per cent of the forecast amount, it is unclear what the resulting actual O&M FTEs would be. The Commission considers that this makes it difficult to assess whether the amounts subject to deferral are material or not. The Commission considers that it is reasonable to expect that ATCO Electric will be undertaking some capital project activity during the test period. Additionally, no party has recommended that the capital project forecast be reduced to zero. Therefore, at least some O&M FTEs will be required during the test period.

269. The Commission also agrees with ATCO Electric that not all of the forecast O&M FTE increases are a result of capital growth. The ADC has provided no explanation why the forecast O&M FTE additions required for reasons other than capital growth would not be achieved. Accordingly, it would not be reasonable to include these employees in a deferral account.

270. In addition, the revenue requirement reduction amounts of $2.7 million for 2013 and $5.6 million for 2014 calculated by the ADC approximate what the maximum balance would be in the deferral account. This assumes that ATCO Electric will not hire any O&M FTEs over the 2013-2014 test period. This is not a reasonable assumption, especially given that some capital project work will be taking place in 2013 and 2014. The Commission considers that a difference of 50 per cent of the ADC's calculation would be a better representation of a worst case scenario,

[120] Transcript, Volume 7, page 1409, lines 14-25; page 1410, lines 1-12.

especially because ATCO Electric's forecasting accuracy for transmission O&M employees since 2010 has been reasonable.[121]

271. This worst case scenario would result in balances in the deferral account of $1.35 million for 2013 and $2.8 million for 2014, which represents approximately 0.25[122] per cent of the 2013 forecast revenue requirement of $536.3 million and 0.4[123] per cent of the 2014 forecast revenue requirement of $662.7 million. These amounts are not material.

272. For all the reasons discussed above, the Commission rejects the ADC's request to establish a deferral account for the O&M labour force.

7.1.3 Station and overhead line maintenance – corrective and emergency maintenance costs

273. ATCO Electric included the following information regarding direct O&M accounts 562 (station equipment expenses) and 563/569 (overhead lines expenses & operations maintenance).

Table 12. Station and overhead line maintenance costs[124]

		2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
		($ million)				
562	Station equipment expenses	7.0	7.1	7.3	8.6	9.6
563/569	Overhead lines expenses & operations maintenance	3.8	3.6	3.8	4.0	4.9
	Total	10.8	10.7	11.1	12.6	14.5

274. ATCO Electric stated that its field staff performs approximately 3,500 preventative maintenance procedures, including insulating oil testing, relay testing, telecommunication equipment testing, thermal scanning, patrols and inspections on transmission lines, and wood pole testing programs. It advised that information gained from these preventative procedures led to approximately 3,000 corrective actions in 2011. Corrective maintenance constitutes the repair or reconditioning of apparatus subcomponents. It further submitted that field staff maintains stand-by services providing emergency response to facility outages and failures 24 hours a day, every day of the year, and as its facilities grow, the amount of preventive, corrective and emergency work it does also needs to grow.

275. The CCA requested more information in order to better understand the changes in the expenditures in these accounts. ATCO Electric provided its response to information request CCA-AE-019 in Exhibit 53.01, stating that it does not forecast corrective or emergency maintenance routines, nor does it track the costs of these separately. The CCA argued, however, that based on the testimony of Ms. Clark, an ATCO Electric witness, it appears that ATCO Electric used historic trends and response rates to determine the volume of work needed for the forecast period.

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[121] Exhibit 188.02, Schedule 5-5, line 18 shows the following: 2010 – applied for of 179.5, actual of 177.5. This is a difference of two FTEs or 1.1 per cent; 2011 – applied for of 203.1, actual of 191.2. This is a difference of 11.9 FTEs or 5.9 per cent.; 2012 – applied for of 212.3, actual of 217.4. This is a difference of (5.1) FTEs or (2.4) per cent. The three-year total is applied for of 594.9 and actuals of 586.1. This is a difference of 8.8 FTEs or 1.5 per cent.

[122] 1.35/536.3 = 0.25 per cent.

[123] 2.80/662.7 = 0.40 per cent.

[124] Exhibit 188.02, Schedule 5-1.

276. The CCA asserted that for the Commission and interveners to make a reasoned assessment of whether corrective and emergency maintenance costs are material and reasonable, ATCO Electric should be directed to provide, at its next GTA, full details of the derivation of corrective and emergency maintenance costs.

277. ATCO Electric submitted that it has provided sufficient information regarding the derivation of these costs, and all costs included in accounts 562 and 563/569 and argued that it did not specifically cite an increase in the volume of corrective and emergency maintenance as a significant driver of resource or cost increases. However, additional assets drive additional work in many areas, all of which ATCO Electric has considered while developing the forecast.

278. ATCO Electric submitted that it is aware of the historic cost trends for emergency and corrective maintenance and that it indicated, in response to information request CCA-AE-019(a), that the average number of FTEs required per year to undertake emergency and corrective maintenance is five. Using the labour cost of $105,000 per FTE, the total annual emergency and corrective maintenance labour equivalent cost is approximately $525,000, roughly four per cent of the total costs in accounts 562 and 563/569.

279. ATCO Electric argued that, by their very nature, emergency and corrective maintenance activities are neither predictable nor controllable. It submitted that gathering more detailed information on emergency and corrective maintenance activities would be an onerous task which would require the establishment of systems and use of resources to monitor and track information in these systems, and it asserted that the costs associated with establishing and monitoring such systems would outweigh any possible benefits of doing so.

Commission findings

280. The Commission agrees with the CCA that, in order to make a reasoned assessment of whether ATCO Electric's corrective and emergency maintenance costs are material and reasonable, how corrective and emergency maintenance costs are derived must be known. While ATCO Electric provided the approximate labour costs associated with the corrective and emergency maintenance area, it stated that it was unable to provide any other costs as these are not tracked separately. The Commission agrees that these labour costs are not a significant part of the overall total forecast costs in this area, however, the Commission and interveners have no way of determining whether the other costs associated with corrective and emergency maintenance are insignificant, and such information would be beneficial in order to make such an assessment.

281. In response to information request CCA-AE-019(b) ATCO Electric included the following:

> Intrusive preventive maintenance routines have a cost, both in terms of the direct costs associated with the completion of the routines – travel, labour, materials and equipment, and in terms of outages, increased risk to the system and increased risk to personnel. The goal and challenge of any good maintenance program is to find the "sweet spot" where just the right amount of preventive maintenance is being performed to prevent equipment from failing in service. Theoretically, perfect preventative maintenance programs will eliminate the requirement for corrective and emergency maintenance by identifying equipment problems just before they happen.

> The FMMS has been in place long enough that several cycles of maintenance data are available for most of major substation apparatus. Using industry standard tools (i.e. Reliability Centered Maintenance, Root Cause Failure Analysis, etc.) ATCO Electric Transmission has started to evaluate our maintenance routines against the data collected. The goal is to identify changes to the routines that will optimize asset management practices including.
>
> - The use of resources (labour, material, tools);
> - The reduction of planned outages;
> - The reduction of unplanned outages;
> - Performing the correct Inspecting/ maintaining routine at the correct time;
>
> and
>
> - Capital investment in assets.

282. ATCO Electric stated that the cost of intrusive preventative maintenance routines includes costs for travel, labour, materials and equipment, and it added that the goal of a good maintenance program is to find the "sweet spot." Likewise, ATCO Electric discussed the optimization of the use of resources (labour, material, tools). The Commission is left to wonder how this "sweet spot" is achieved, and how the optimization will occur, if there are no costs tracked separately for labour, material and tools. Such information would be beneficial to ATCO Electric in order to evaluate the effectiveness of such corrective and emergency maintenance.

283. Although ATCO Electric stated that the costs to be incurred to track costs associated with corrective and emergency maintenance would outweigh the benefits of any such information, it did not submit any cost/benefit information to support this statement.

284. The Commission directs ATCO Electric to provide, in its next GTA, an estimate of the costs and benefits associated with corrective and emergency maintenance procedures, to support its forecast labour and non-labour costs. It also directs ATCO Electric, as part of its next transmission GTA, to include information on how it evaluates all of the costs associated with its maintenance activities, as it explained in the quote in paragraph 281 of this decision.

7.1.4 Account 560: supervision and engineering; Account 561: control centre operations; Account 562: station equipment expenses

285. ATCO Electric included the following information regarding direct O&M accounts 560, 561 and 562.

Table 13. Accounts 560, 561 and 562[125]

		2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
		($ million)				
560	Supervising and engineering	3.0	3.2	3.8	4.6	5.3
561	Control centre operations	2.1	2.4	3.4	3.8	4.4
562	Station equipment expenses	7.0	7.1	7.3	8.6	9.6
	Total	12.1	12.7	14.5	17.0	19.3

286. The CCA submitted that, due to labour vacancies, ATCO Electric experienced significant savings relative to the approved forecast in these three accounts over the three years from 2010 to 2012.[126]

287. The CCA argued that there is no evidence to suggest that ATCO Electric's assumption that the labour vacancies experienced in these three accounts over the years 2010-2012 will cease or disappear over the 2013-2014 test period, adding that despite ATCO Electric's submission that it had implemented programs to address these vacancies over the test period, labour vacancies did occur over the 2010-2012 period, even though some of these programs had been in place for quite a while. The CCA recommended that the Commission reduce the combined costs in accounts 560, 561, and 562 by $1.6 million in each of the test years.

288. ATCO Electric argued that the CCA's assertion is incorrect and that it has hired seven new transmission operators (Account 561) between January 2011 and June 2012, which was directly attributable to an employee referral program and "retire/rehire" program targeting former operators from ATCO Electric and other utilities. Further, it submitted that its bursary and summer employment programs have helped it attract nine electrical technologists (Account 562), and seven candidates for permanent electrical technologists over the test period, and that increasing VPP eligibility in 2011 and 2012, and beyond, as proposed in the application, has had a positive influence on its ability to attract and retain employees.

289. ATCO Electric submitted that its proposed vacancy rate of six per cent for transmission direct O&M is based on aggregate vacancy rates for all O&M FTEs distributed across all accounts, including accounts 560, 561 and 562. Therefore, implementing the CCA's suggestion would in effect be double-counting the influence of vacancies in these accounts, as they are already taken into account in ATCO Electric's overall direct O&M vacancy rate. ATCO Electric further submitted that instead of looking at its overall variance for direct O&M, the CCA has chosen to look at these three accounts in isolation; in effect "cherry-picking," which does not accurately reflect ATCO Electric's actual expenditures and accuracy of forecasting for O&M costs.

[125] Exhibit 188.02, Schedule 5-1.
[126] Exhibit 235.01, argument of the CCA, paragraphs 58-63.

Commission findings

290. Any variances between the actual and forecast FTEs for accounts 560, 561 and 562 for the years 2010 to 2012 are reflected in the calculation of the labour vacancy rate for transmission. Further reducing the forecast amounts in these three accounts, because of labour vacancies, would in effect be double-counting the vacancy rate; otherwise, there would be separate labour vacancy rates for each O&M account. Therefore, it is inappropriate to look at the individual vacancy rates in any account in isolation. The CCA made no recommendation nor raised any issue with ATCO Electric's forecast of its direct O&M vacancy rate and, in Section 5.4.2 of this decision, the Commission approved ATCO Electric's requested vacancy rate for direct O&M as filed. For the above reasons, the Commission rejects the CCA's recommendation to reduce the combined forecast amounts for accounts 560, 561, and 562 by $1.6 million in each of 2013 and 2014.

7.1.5 Account 567: annual structure payments

291. Background information about annual structure payments (or right-of-way payments) is included in Section 5.1.2 of this decision. In the omissions and updates filing, ATCO Electric included forecast annual structure payment amounts of $4.0 million for 2013 and $4.4 million for 2014.

Commission findings

292. In Section 5.1.2 of this decision, the Commission examined the request from ATCO Electric for deferral treatment with respect to these annual structure payments. As part of that examination, the Commission prepared a table[127] (Table 4) which detailed the actual and forecast annual structure payment costs of ATCO Electric for the years 2007-2011. From the information in Table 4 of this decision, it is clear that for each of the years 2007, 2008, 2009, 2010 and 2011 ATCO Electric's actual annual structure payments were substantially lower than the approved forecast amounts. This trend is also forecast to continue in 2012 based on the figures for 2012 in Schedule 5-1 of the supporting revenue requirement schedules filed in conjunction with the omissions and updates filing.[128]

293. Based on the information included in Table 4 of this decision, and the 2012 forecasting inaccuracy, the Commission considers that a 20 per cent reduction would be reasonable with respect to the forecast annual structure payments requested by ATCO Electric. This reduction is derived by weighting more heavily the forecasting accuracy variances of (16.1) per cent in 2011 and (22.5) per cent in 2012.

294. However, the Commission is mindful of the provisions under Section 46(2) of the *Transmission Regulation* that require the Commission to consider actual payments made to landowners pursuant to an agreement between the landowner and the utility to be prudent unless an interested person satisfies the Commission that the payments are unreasonable. For the reason, the Commission has continued to provide a deferral account for this expense. Consequently, any variance in the forecast will be adjusted to the final actual costs for this expense at that time. On this basis, the Commission approves the annual structure payments of $4.0 million for 2013 and $4.4 million for 2014, as applied for by ATCO Electric.

[127] Table 4, in paragraph 50.
[128] Exhibit 188.02, Schedule 5-1 shows a 2012 forecast of $3.1 million with a 2012 applied for amount of $4.0 million. This is a difference of $0.9 million or 22.5 per cent.

7.1.6 Incentive allowance for transmission linemen crews

295. ATCO Electric advised that it has several vacancies for transmission linemen and is currently only able to deploy four crews. It added that these crews are expected to be significantly impacted by retirements over the next five years and, without immediate action, it will not be able to sustain enough crews to manage ongoing maintenance work on transmission facilities and provide emergency response. It stated that, in order to rebuild the transmission linemen crews, it planned to implement a retention and attraction incentive in 2012. This incentive will pay transmission line crew members an incentive allowance after 24 months of continual employment on a transmission line crew.

296. In response to information request AUC-AE-010,[129] ATCO Electric included more information about the details of this program and how the forecast amounts were calculated. The incentive allowance for an eligible employee is equal to 20 per cent of the employee's salary in 2013 and 20 per cent of the employee's salary in 2014, but the total amount is only paid after 24 months of continual employment. ATCO Electric advised that the program will start on January 1, 2013. Forecast payments were included in the calculation of the 2014 revenue requirement, and the O&M component of the forecast payments were included in Account 563/569 (Overhead lines expenses & operation maintenance). In addition, the program was forecast to include 32 employees and the forecast allowance payments were approximately $1.3 million in total, with 50 per cent being allocated to capital and the 50 per cent being allocated to O&M account 563/569.

297. During questioning from Commission counsel, an ATCO Electric witness advised that the program sign-up actually started in late 2012, and that the first payments will be made in 2014.[130]

Commission findings

298. Because the program provides a strong incentive to remain employed as a member of a line crew for 24 consecutive months, the Commission approves the inclusion of this program in the calculation of the revenue requirement for 2014.

299. ATCO Electric advised that it had built no contingency into the forecast for these incentive allowances;[131] that is it has assumed that it will be able to sign up 32 employees for this program in late 2012, and that none of them will leave over the 24-month period. ATCO Electric stated:

> Attracting and retaining linemen with transmission line maintenance experience has been difficult. ATCO Electric's transmission facilities span some of the most remote areas of the province and traverse challenging geographic terrain. Transmission line maintenance work is very physically demanding, working conditions are trying, and a significant amount of time away from home is involved so employees are separated from their families for a significant amount of time during the year. As a result, most linemen hired to work on a transmission crew transfer as soon as an opening is available.[132]

[129] Exhibit 50.01.
[130] Transcript, Volume 3, page 506, line 18-25; page 507, lines 1-4.
[131] Transcript, Volume 3, page 507, lines 24-25; page 508, lines 1-6.
[132] Exhibit 1, application, Section 5, paragraph 139.

300. While an ATCO Electric witness indicated that they would be surprised to see anyone leave the program during the 24-month period,[133] the Commission does not share this optimism based on the difficulties ATCO Electric described with attracting and retaining these employees, as quoted in the previous paragraph. In addition, while the ATCO Electric witness advised that all linemen, with the exception of one, had signed up for the program, the witness was not sure exactly how many people had signed up.[134]

301. Based on this uncertainty about the number of employees actually signed up for the program and the difficulties associated with retaining transmission line crew members, the forecast assumptions of signing up 32 employees in 2012 and retaining them all over the ensuing 24-month period are overly optimistic and therefore not reasonable. The Commission finds that the forecast cost of this program should be reduced by 10 per cent and directs ATCO Electric to reflect this 10 per cent reduction in the compliance filing. This reduction is to be allocated 50 per cent to O&M Account 563/569 and 50 per cent to capital.

302. The Commission is interested in how successful this program will be and directs ATCO Electric, in its next GTA, to include an update on the status of this incentive allowance program. Such an update should include, but not be limited to, information on how many of the forecast 32 crew members actually signed up for the program in late 2012, how many forfeited the allowance by leaving before the 24-month period, and how many are still eligible for the incentive allowance payment. ATCO Electric should also indicate whether it intends to continue and/or vary the program as part of its next GTA.

7.2 Allocated share of general operation and maintenance costs

303. General O&M is primarily comprised of the ongoing costs to manage and maintain the telecommunications network and the buildings, warehouses and facilities from which ATCO Electric conducts operations. There are methods used to allocate the total general O&M costs to the transmission and distribution business units. Any issues that were raised with respect to the cost allocation methods are discussed in Section 13 of this decision.

304. ATCO Electric included the following information regarding transmission's allocated share of general O&M costs.

Table 14. Transmission function's share of general operation and maintenance costs[135]

2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
($ million)				
3.9	4.3	4.9	6.3	6.9

305. ATCO Electric advised that the $1.4 million increase between the 2012 forecast and the 2013 forecast was due to general communication equipment ($0.5 million) and maintenance of offices, warehouses and yards ($0.9 million). It also advised that the $0.6 million increase between the 2013 forecast and the 2014 forecast was due to general communication equipment ($0.3 million) and maintenance of offices, warehouses and yards ($0.3 million). In response to

[133] Transcript, Volume 3, page 508, lines 3-6.
[134] Transcript, Volume 3, page 507, lines 8-17.
[135] Exhibit 188.02, Schedule 5-1.

information request CCA-AE-026(e),[136] ATCO Electric provided a correction to a variance explanation included on lines 7-10 of Schedule 23-2 of the application.

306. The CCA raised an issue with the forecast costs for maintenance of offices, warehouses and yards.

Discussion of the issues

307. ATCO Electric submitted that it had embarked on a program to construct and renovate a number of buildings to accommodate increased staffing requirements and transmission services and, as a result, increased the total square footage of its building portfolio attributable to transmission by 54,000 square feet in 2013 and an additional 18,000 square feet in 2014.

308. ATCO Electric further submitted that consultants, Life Cycle Value Management (LCVM), conducted an analysis of ATCO Electric's buildings and determined that an appropriate cost per square foot to operate and maintain modern buildings is $9.94 per square foot. ATCO Electric stated that it also had another consulting company, Harvard Property Management, validate LCVM's analysis as reasonable, and that it was forecasting to hire additional FTEs to support building operations at a forecast cost of $0.2 million and $0.3 million in 2013 and 2014 respectively.[137] It added that the costs for these FTEs are in addition to the cost increase resulting from the additional space.

309. In response to an information request, ATCO Electric provided a table showing the building O&M costs per square foot for transmission offices, warehouses and other facilities for each of the years from 2008 to 2014.

Table 15. Building operation and maintenance costs[138]

	2008	2009	2010	2011	2012	2013	2014
Total costs	$863,244	$788,013	$762,768	$930,353	$965,733	$1,745,903	$1,947,865
Square footage	98,782	96,473	98,527	101,950	103,127	157,639	175,907
Cost per square foot	$8.74	$8.17	$7.74	$9.13	$9.36	$11.08	$11.07

310. During the oral hearing, the ATCO Electric general panel was questioned by counsel for the CCA about the specific drivers for the increase in the per square foot costs. Part of the reply given by Mr. Babyn was the following:

> A. MR. BABYN: And most of that square footage is for the new buildings that we have added throughout ATCO Electric. And so that -- that is one of the drivers. The other component of that -- so out of that, just on a square-footage basis if I just look at it from a dollars point of view, you know, in 2013 it's probably around 550 or $600,000, just increase for square-footage costs for new buildings.
> In addition to that, we have some FTE additions that are going to be -- that are incorporated into the $1.745 million, so we've got about a couple hundred

[136] Exhibit 53.01.
[137] Exhibit 52.01, response to information request ADC-AE-085(b).
[138] Exhibit 53.01, response to information request CCA-AE-038(d).

> thousand dollars in FTE additions.
> Now, for all of the buildings, the new buildings that ATCO Electric is constructing and that are coming into service, we will have building operators providing operating services in those buildings. So they're very significant new buildings with very complex, you know, operating systems in them. They're larger buildings than we have ever had in our fleet of buildings. And so, you know, we need very focused expertise to help us manage those.[139]

311. The CCA submitted that any maintenance cost increases above those commensurate with a change in square footage and inflation, such as those with regard to the two additional FTEs, are unacceptable. It argued that, if anything, ATCO Electric should be able to achieve efficiencies through economies of scale as the square footage under management grows. Additionally, the CCA submitted that ATCO Electric has not explained what additional complexities are entailed in the new buildings that would be driving the additional costs. The CCA recommended that the maintenance of company owned warehouses and offices be reduced by $0.2 million, representing the cost of the two FTEs, in each of 2013 and 2014.

312. ATCO Electric replied that it had detailed the need for these two FTEs in response to an information request from the ADC.[140] More specifically, ATCO Electric reiterated that the two FTEs were responsible for ensuring site safety and security compliance, soliciting bids and hiring contract resources, completing and enforcing contracts, providing dispute resolution on work completed, validating invoices, budgeting, ensuring regulatory compliance and monitoring, adjustment of the heating, ventilation and air conditioning systems, lighting systems and other minor reports. It further submitted that the majority of the space in the new buildings, and associated operating costs, has been allocated to distribution.

313. Additionally, ATCO Electric submitted that its forecast costs per square foot of $11.08 (2013) and $11.07 (2014) are low in comparison to similar operating cost figures ranging between $13.70 per square foot to $17.33 per square foot.

Commission findings

314. The variance explanations provided by ATCO Electric with respect to the cost increases in the entire allocated general O&M area are inconsistent. In paragraph 277 of Section 23 of the application, ATCO Electric advised that the $1.4 million increase between the 2012 forecast and the 2013 forecast was due to general communication equipment ($0.5 million) and maintenance of offices, warehouses and yards ($0.9 million). ATCO Electric also advised that the $0.6 million increase between the 2013 forecast and the 2014 forecast was due to general communication equipment ($0.3 million) and maintenance of offices, warehouses and yards ($0.3 million). This makes the total increases for 2013 and 2014 attributed to maintenance of offices, warehouses and yards equal to $1.2 million.

315. In Table 23-1 of the application,[141] ATCO Electric provided information about the incremental O&M costs associated with transmission's incremental square footage. The total shown in Table 23-1 is $1.2 million using the incremental square footage for transmission and

[139] Transcript, Volume 2, page 369, lines 8-25; page 370, lines 1-2.
[140] Exhibit 52.01, response to ADC-AE-085(b).
[141] Exhibit 1, application, Section 23, paragraph 285.

the $9.94 per square foot cost. This appears to explain the entire variance for the 2013-2014 test period attributed to the maintenance of offices, warehouses and yards as discussed in the previous paragraph. ATCO Electric confirmed in response to information request UCA-AE-017(i)[142] that the total of $1.2 million in Table 23-1 is incorporated into the forecasts of $0.9 million for 2013 and of $0.3 million for 2014. Again, this is in agreement with the information provided in paragraph 277 of the application.

316. In response to information request CCA-AE-038(a),[143] when requested to provide a breakout of general O&M costs showing the costs to manage and maintain the telecommunications network and the costs to manage buildings, warehouses and facilities, separately, ATCO Electric provided a table for the entire company. However, the totals on the table provided in the response to information request CCA-AE-038(a) do not agree to the total forecast amounts included in Schedule 23-1 of the application. This indicates to the Commission that there are potentially more costs included in the forecast for general O&M; however, there were never any details provided on the nature of these additional costs, or whether there were any differences in the costs for these areas that needed to be explained.

317. In response to information request CCA-AE-038(d), when requested to calculate the O&M costs for the buildings whose costs were included in the response to part (a) of the information request, ATCO Electric only provided an analysis for the transmission function, which is reflected in Table 15 above. It would have been more helpful for ATCO Electric to provide the information on a total company basis and show how the transmission share was determined, using the total costs and the allocation factors included in Section 27 of the application. Further, because of the change in allocation factors for general O&M, ATCO Electric indicated in paragraph 343 of the application[144] that "[a]s a result of updating the assignment percentages, there has been a $0.4 million and $0.5 million impact on the allocation of costs between Transmission and Distribution for the 2013 and 2014 test period, respectively." The information provided in Table 27.1 of the application[145] demonstrates that this is an increase in general O&M costs for the transmission function. ATCO Electric has not explained where these increases of $0.4 million and $0.5 million for the transmission function's share of general O&M have been accounted for in the variance explanations.

318. At the oral hearing, an ATCO Electric witness brought up an additional variance explanation regarding the increase in transmission's share of the costs for the maintenance of offices, warehouses and yards over the test period, which included the addition of some FTEs. Although the exact number of FTEs was not provided, the dollar amounts were, and these amounts matched the amount provided by ATCO Electric in the response to information request ADC-AE-085(b).[146] ATCO Electric has not explained how the addition of these extra FTEs is reflected in the variance explanation amounts provided in paragraph 277 of the application.

319. The information provided by ATCO Electric in the response to information request CCA-AE-038(d), as reproduced in Table 15 of this decision, does not provide adequate support for the forecast amounts included in the application for the maintenance of offices, warehouses, and yards. The information provided in response to information request CCA-AE-038(d) is also

[142] Exhibit 51.01.
[143] Exhibit 53.01.
[144] Exhibit 1, application, Section 27.
[145] Exhibit 1, application, Section 27, paragraph 342.
[146] Exhibit 52.01.

not consistent. Calculating the difference in the square footage between 2012 and 2014, from the information provided, results in an increase of 72,780 square feet allocated to transmission. This does not agree to the 116,402 of incremental square feet allocated to transmission as shown in Table 23-1 of the application.

320. The Commission also finds that the cost per square foot in 2013 of $11.08 and the 2014 amount of $11.07[147] are not explained, given the $9.94 dollar amount provided in the LCVM report. ATCO Electric stated in paragraph 286 of the application,[148] in reference to the $9.94 per square foot amount, that "[t]he forecast to maintain offices, warehouses and yards is based on this cost and the projected in-service date (ISD) of new / renovated buildings throughout the test period." ATCO Electric has not demonstrated how the $9.94 was used in the preparation of the forecast; rather, all that is shown, as reproduced in Table 15 of this decision, is a cost per square foot of $11.08 in 2013 and $11.07 in 2014.

321. In the response provided to information request UCA-AE-017(c),[149] ATCO Electric does provide information about the total costs for general O&M for the periods 2010 to 2014, including how much is allocated to both the distribution and transmission functions. The Commission has confirmed that the totals for the entire company, as well as the transmission and distribution share, correspond to the information provided in Schedule 23-1 of the application. However, the information provided in response to information request UCA-AE-017(c) does not provide any information about what is causing the increase in the total company forecast amounts for 2013 and 2014.

322. The variance explanations provided by ATCO Electric in Schedule 23-2-T of the application[150] for the transmission function's share of general O&M costs increasing over the 2013-2014 test period are as follows:

> The increase of $1.4 in 2013 is due to higher utilities and maintenance for a new building in Grande Prairie ($0.8), as well as staff additions in the Building and Construction Maintenance group, Comm Tech (Qualified), Comm Tech (Team Lead), and TRT Qualified ($0.6).
>
> The increase of $0.6 in 2014 is mainly due to staff additions in the Building and Construction Maintenance group, Comm Tech (Qualified), TRT Qualified ($0.6), and a Clerk ($0.3), as well as higher utilities and contractor maintenance costs for the Grande Prairie building ($0.3).

323. These variance amounts add another level of detail that is in contradiction to other variance explanations provided. As discussed previously, there was an increase mentioned in paragraph 343 of the application resulting from a difference in allocations. This is not mentioned at all in Schedule 23-2-T.

324. Because of the uncertainty of the reasons for the increase in 2013 and 2014 with respect to the whole area of maintenance of offices, warehouses, and yards, ATCO Electric has not explained clearly why the costs are increasing; hence the Commission has no basis upon which

[147] As included in Table 15 of this decision.
[148] Exhibit 1, application, Section 23.
[149] Exhibit 51.01.
[150] The same explanations were included in Schedule 23-2-T of the supporting revenue requirement schedules that were provided in conjunction with the omissions and updates filing. These schedules are in Exhibit 188.02.

to assess the reasonableness of the entirety of the forecast requested. The recommendation by the CCA for a $0.2 million reduction in the transmission function's share of general O&M is a reasonable request, considering the level of uncertainty. Therefore, the Commission directs ATCO Electric, in the compliance filing, to reduce the transmission function's allocated share of general O&M costs in 2013 and 2014 by $0.2 million in each year. The Commission considers this is reasonable in light of the $9.94 figure amount provided by LCVM. Using the square footage information provided in Table 15 of this decision of 157,639 and 175,907 for 2013 and 2014 respectively, and applying the $9.94 amount to them, results in figures of approximately $1.57 million for 2013, and $1.75 million for 2014. Comparing these figures to the ones in Table 15 results in a difference of $0.18 million for 2013 and $0.2 million for 2014.[151]

7.3 Allocated administrative and general costs

Commission findings

325. In response to a Commission question[152] about the supporting revenue requirement schedules that were submitted in conjunction with the omissions and updates filing, ATCO Electric advised that Schedule 25-4 of the supporting revenue requirement schedules had not been updated. It is important to have a full and complete set of supporting schedules in which all the cross referenced figures agree. Accordingly, the Commission directs ATCO Electric, in the compliance filing, to submit a full and complete set of supporting revenue requirement schedules that reflect all of the findings and directions in this decision.

8 Depreciation

326. ATCO Electric submitted that the forecast depreciation expense for the 2013 and 2014 test years relied on updated depreciation rates determined as part of a technical update. The depreciation parameters used in the technical update had been previously approved in Decision 2011-134 and continue to remain applicable in this application. ATCO Electric indicated that it continued with its past practice of including the impact of forecast capital additions on the transmission composite depreciation rate for each account and that the amortization of accumulated depreciation differences are the same amounts as those approved in Decision 2011-134. It stated that its filing with respect to depreciation expense was in compliance with the Commission's MFR.

327. In response to information request AUC-AE-015,[153] ATCO Electric provided the basis for the gross amortization of contributions and capitalized vehicle depreciation over the test period. In response to information requests AUC-AE-013(a) and AUC-AE-016,[154] ATCO Electric discussed the allocation of certain general plant accounts in addition to Rural Electrification Association/Farm assets, both of which concerned the portion allocated to the transmission function. It also provided detailed calculations with respect to both the transmission isolated plant amortization including forecast retirement dates, and software amortization, in response to information request AUC-AE-019.[155]

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[151] For 2013: amount reported in Table 15: $1.75 million less the $1.57 million = $0.18 million. For 2014: amount reported in Table 15: $1.95 million less the $1.75 million = $0.20 million.
[152] Exhibit 226.01, response to AUC-AE-005.
[153] Exhibit 50.01.
[154] Exhibit 50.01.
[155] Exhibit 50.01.

Commission findings

328. With the exception of the deferral account related to changes in depreciation rates required under IFRS, parties identified no significant issues in respect of the depreciation expense determined for the 2013 and 2014 test years.

329. ATCO Electric stated that it determined depreciation expense over the test period in accordance with previously approved depreciation methodologies and reporting requirements, and included a level of supporting backup on this record that is acceptable.

330. While ATCO Electric's forecast depreciation expense over the test period has increased significantly compared to previous years, it is attributable largely to the year over year increase in total property, plant and equipment directly related to its forecast capital additions. This can be observed in the following table prepared by the Commission.

Table 16. Comparison of year over year depreciation expense with property, plant and equipment balances[156]

	2010 actual	2011 actual	2012 forecast	2013 forecast	2014 forecast
	($ million)				
Depreciation	57.0	66.8	85.7	117.2	147.8
Property, plant and equipment	2,110.2	2,349.6	3,088.0	4,585.9	6,747.4

331. The forecast property, plant and equipment balance of $6,747.4 million at the end of 2014 includes $1,567.5 million[157] for the forecast cost of the EATL capital project; however, the forecast depreciation expense for 2014 includes no amount for depreciation for the EATL project as the project's forecast ISD is December 31, 2014.[158]

332. The Commission agrees that ATCO Electric's forecast depreciation rates for 2013 and 2014 are reasonable and fully supported and are therefore approved as filed. The Commission directs ATCO Electric, in the compliance filing, 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.

333. The amortization of accumulated depreciation differences is the same as approved in Decision 2011-134, and was last calculated by ATCO Electric using data as of December 31, 2008.[159] This is evidence that the magnitude of changes due to either depreciation parameters or the composition of plant balances that might have an impact on the depreciation variance has been, or is expected to be, minimal. In this respect, it is apparent to the Commission that ATCO Electric continues to be satisfied with these amounts and it did not seek approval from the Commission in its last depreciation study for an update to its annual provision for true-up related to the accumulated depreciation differences as calculated at December 31, 2008.

[156] Exhibit 188.02, Schedule 6-1, line 10; Schedule 10-2, line 15.
[157] Exhibit 188.02, Schedule 10-4, line 440.
[158] Exhibit 1, application, Section 10, paragraph 215.
[159] Exhibit 188.02, Schedule 6-3 and Schedule 6-4 "For True-up Related to Estimated Original Cost as of December 31, 2008."

334. However, parties would benefit from ATCO Electric preparing an update to the annual provision for true-up, and the Commission consequently directs ATCO Electric to prepare such an update at the time of its next depreciation study.

335. In response to a Commission question[160] about the supporting revenue requirement schedules that were submitted in conjunction with the omissions and updates filing, ATCO Electric advised that the depreciation amount for 2013 for direct general property, plant and equipment on line nine of Schedule 6-2 should agree with the cross reference in Schedule 6-6. In the same response, ATCO Electric stated that it would incorporate this update in the compliance filing. It is important to have a full and complete set of supporting schedules in which all the cross referenced figures agree. In paragraph 325 of this decision, the Commission directed ATCO Electric to submit a full and complete set of supporting revenue requirement schedules; it further directs that all cross references in those supporting revenue requirement schedules agree, including the one discussed in this paragraph.

8.1 Isolated generation forecast retirement dates

336. In the application, ATCO Electric included Schedule 6-5 entitled "Schedule of Isolated Generation Forecast Retirement Dates." In response to information request AUC-AE-019(a),[161] ATCO Electric provided an updated Schedule 6-5 to reflect an incorrect retirement date for the Chipewyan Lake units, and add some units that were missing from the original schedule. The information in the updated Schedule 6-5 provided in the response to the information request was also the same as that included in Schedule 6-5 of the supporting revenue requirement schedules[162] submitted in conjunction with the omissions and updates filing, with one exception.

337. With respect to the Steen River Unit CUL 441, the retirement date included in the response to information request AUC-AE-019(a) is 2032; however, the retirement date included in the supporting revenue requirement schedules is 2031. It is important to know the correct retirement date for this unit. Therefore, the Commission directs ATCO Electric, as part of the compliance filing, to provide the correct retirement date for Steen River Unit CUL 441 and to include the correct retirement date in Schedule 6-5 in the compliance filing.

9 Income taxes

338. ATCO Electric prepared its income tax forecast using the liability method for both federal and provincial income taxes.

339. ATCO Electric explained that, in its 2011-2012 GTA, it applied to change from the flow-through to the liability method for transmission federal income taxes. In Decision 2011-134, the Commission approved ATCO Electric's adoption of the liability method for transmission federal income taxes beginning in 2011. ATCO Electric added that, as described in sections 1 and 28 of this application, it was now seeking to include provincial FIT as well as federal FIT in order to maintain credit metrics at an appropriate level. It stated that it is not applying for the settlement of unrecovered transmission federal deferred income taxes pertaining to years prior to 2011 or unrecovered transmission provincial deferred income taxes pertaining to years prior to 2013 as

[160] Exhibit 226.01, response to AUC-AE-002.
[161] Exhibit 50.01.
[162] Exhibit 188.02.

part of this application; given that this requested liability method treatment is for temporary relief during the period of significant capital growth.

340. ATCO Electric advised that, under the liability method, future tax liabilities are recognized for the estimated tax consequences attributable to the difference between financial statements carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted tax rates and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

341. ATCO Electric indicated that the income tax amounts have been calculated using the following substantively enacted tax rates:

Table 17. Substantively enacted tax rates used[163]

	2013 forecast (%)	2014 forecast (%)
Federal income tax	15.00	15.00
Provincial income tax	10.00	10.00
Federal future tax	15.00	15.00
Provincial future tax	10.00	10.00

342. ATCO Electric advised that, in determining the federal and provincial taxable income, as shown in Schedule 7-3 of the application, a number of items are either added to or deducted from the utility earnings before tax and it added that, where possible, these items have been directly assigned to the transmission function. This includes depreciation and capital cost allowance (excluding the corporate general property, plant and equipment), engineering, supervision and general (ES&G), capital repair costs, removal and abandonment costs, deferrals for tax purposes and the Part VI.I tax deduction. For the items that are not directly assigned, the cost functionalization methodology outlined in Section 27 of the application was used where possible. This includes the items relating to the reserve for injuries and damages, rate case expenses and claims, as well as depreciation and capital cost allowance on corporate general property, plant and equipment.

Commission findings

343. Other than the issue of whether ATCO Electric should be permitted to recover both federal and provincial FIT, no other issues were raised concerning the income tax forecast. The Commission has addressed the issue of the collection of FIT in Section 14.7 of this decision.

344. The Commission finds that the income tax rates used in the preparation of the application are the substantively enacted rates and therefore approves them as filed. In Section 5.1.8 of this decision, the Commission also made findings with respect to the deferral account for income taxes. The Commission directs ATCO Electric, in the compliance filing, to update the income tax expense calculations for 2013 and 2014 where necessary to reflect the findings and directions made by the Commission in all other areas of this decision.

[163] Exhibit 1, application, Section 7, paragraph 166.

10 Revenue offsets

345. ATCO Electric's revenue offsets include facility charges, affiliate revenue, other revenues, and revenue related to services provided to outside parties. These revenues shown in Table 18 below, help offset the revenue requirements that ATCO Electric would otherwise request. No issues were raised by parties regarding the forecast level of revenue offsets.

Table 18. Transmission revenue offsets[164]

2010 actuals	2011 actuals	2012 forecast	2013 forecast	2014 forecast
($ million)				
3.6	3.9	3.5	3.6	3.7

Commission findings

346. In response to information requests CCA-AE-024(b)[165] and UCA-AE-029(d), ATCO Electric provided an updated revenue offsets forecast for 2014 and a corresponding updated Schedule 8-1. The information in the updated Schedule 8-1 was the same as that included in Schedule 8-1 of the supporting revenue requirement schedules[166] submitted in conjunction with the omissions and updates filing, with one exception.

347. With respect to the "SOP Revenue" and the "Other Revenue" categories, the 2010 actuals included in the response to the information requests CCA-AE-024(b) and UCA-AE-029(d) are $0.5 million and $0.3 million respectively. The 2010 actuals for these categories in Schedule 8-1 included in the supporting revenue requirement schedules are $0.3 million and $0.5 million respectively. For the sake of accuracy and completeness, it is important to reflect the correct actuals for 2010 for these categories. Therefore, the Commission directs ATCO Electric to provide in the compliance filing, the correct 2010 actuals for the "SOP Revenue" and "Other Revenue" categories and to include these correct amounts in Schedule 8-1 in the compliance filing.

11 Rate base

348. Rate base is the utility equivalent of net property, plant and equipment, with an additional component for necessary working capital. The rate base of a utility increases when additions are made to property, plant and equipment, and decreases when capital assets are retired or their cost is adjusted. Rate base also decreases when depreciation is charged against the property, plant and equipment. Mid-year net rate base is the amount upon which return for a utility is calculated. The difference between the mid-year rate base and the mid-year net rate base is generally the amount that has been calculated for mid-year no cost capital and mid-year net customer contributions.

349. The depreciation aspect of rate base has been addressed in Section 8 of this decision; mid-year necessary working capital has been addressed in Section 12, and mid-year no cost capital is addressed in Section 15. The remaining aspects, capital property additions, retirements and adjustments, customer contributions and CWIP, are addressed in this section of the decision.

[164] Exhibit 188.02, Schedule 8-1.
[165] Exhibit 53.01.
[166] Exhibit 188.02.

350. Commencing in 2011, ATCO Electric's transmission function began to receive a return on the mid-year CWIP balances associated with its direct assigned capital projects. CWIP balances are the costs associated with capital projects that have not been completed at the end of the calendar year. This return was permitted to aid in maintaining the credit metrics of ATCO Electric. ATCO Electric has applied for continuation of a return on CWIP balances for the direct assigned capital projects for 2013 and 2014. The Commission has addressed this request in Section 14.7 of this decision.

351. Any CWIP balances at a calendar year-end that are not for a direct assigned capital project have an additional amount added to them called an allowance for funds used during construction (AFUDC). The Commission has addressed this component in Section 11.12 of this decision.

352. Capital expenditures are the amounts that are forecast to be spent in the year, while capital additions are the cumulative amounts spent on capital projects that are forecast to be completed during the year and added to rate base. With the exception of the return on the direct assigned capital projects, for which a deferral account has been established for 2013 and 2014, as explained in Section 5.1.4 of this decision, ATCO Electric takes the forecast risk for 2013 and 2014 associated with the return on all other capital additions that are forecast to take place in 2013 and 2014.

353. As previously detailed in Table 2 of this decision, ATCO Electric has forecast approximately $1.5 billion in property, plant and equipment additions for the year 2013, with an amount of approximately $2.2 billion forecast for 2014. The forecast capital expenditures figure for 2013 is approximately $1.5 billion and the amount forecast for 2014 is approximately $1.2 billion.

11.1 Testing and approving transmission capital projects costs

11.1.1 Introduction

354. The revenue requirement requested for approval in this application is $536.3 million in 2013 and $662.7 million in 2014, representing a 25.3 per cent increase over existing rates in 2013 and a 54.8 per cent increase over existing rates in 2014.[167] All parties in this proceeding acknowledge that these amounts reflect a material increase in transmission rates and further, that the principal driver of this rate increase is the substantial level of direct assigned capital projects expenditures that are forecast to be incurred in the test years along with these projects' associated depreciation, return and income taxes. ATCO Electric adopted a new organizational structure which separated its functions into two separate divisions: operations and capital projects, to better manage this significant forecast capital build.

355. The issues in this proceeding reflected the prominent impact of capital projects on the forecast revenue requirement. The forecast capital costs of two projects in particular, the HRTD program, and the EATL project,[168] with forecast capital additions of $650.7 million in 2013 and $30.1 million in 2014 and $1.568 billion in 2014 respectively, were extensively tested, notwithstanding the fact that direct assigned capital projects are subject to deferral treatment, and the prudence of these final project costs is determined as part of that deferral account process.

[167] Exhibit 117.01, omissions and updates filing.
[168] The EATL project is a designated critical transmission infrastructure project pursuant to Part 2.1 of the *Electric Utilities Act.* As such, the Commission does not determine the need for this project.

356. The submissions of the intervener parties, who represent the Alberta ratepayers who will be required to pay for the costs of the forecast transmission capital build, included not only recommendations to reduce the forecasts of specific projects included in the test period but also broad, policy proposals regarding testing and approving the costs of transmission projects through the life of the project. ATCO Electric opposed these policy proposals stating that they were beyond the scope of this proceeding, beyond the jurisdiction of the Commission or better dealt with either in another forum or in a generic proceeding.

357. This section is intended to explain the role of the Commission in the context of transmission project development in Alberta, to provide clarity to parties regarding the scope of the issues to be addressed in this proceeding, and to respond to the broad policy recommendations regarding transmission development advanced by the interveners, particularly, the RPG.

11.1.2 Legislative overview – approving electric transmission capital costs

358. The legislative scheme for the development of transmission projects in Alberta requires Commission approval throughout the various stages of development and throughout the full lifecycle of a transmission project. A brief overview of the standard approval process for transmission facilities is provided for context.[169]

359. Prior to 1995, regulatory decision-making authority over electric transmission facilities was shared between the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB). In evaluating whether to approve the construction and operation of a new transmission facility, the ERCB evaluated the need for the line and, if needed, where it should be located. The PUB determined whether, once built, the costs of the transmission facilities should be included in rates.

360. This division of authority worked well until the late 1980s. At that time, legal uncertainty arose in situations where the ERCB had approved the need for and construction of a project but, upon completion of construction, the PUB was reluctant to allow the utility to charge customers with the costs of the project because, in its view, the project was not "used or required to be used" because provincial demand had not materialized as forecast.

361. This legal uncertainty was addressed in 1995 with the merger of the PUB and ERCB into the Alberta Energy and Utilities Board (EUB). For purposes of electric facility regulation, this model coordinated approval activities by merging the need, facility and rate approvals into one regulator.

362. In 1996, Alberta's electricity market was restructured. As part of that restructuring, a new two-stage process for the construction of transmission facilities was introduced.

363. Today, the standard regulatory approval process requires that before utility transmission facility projects can be constructed, put into operation or included as part of the rate base of a utility, a number of regulatory approvals are required. Commission approval is required at three major stages: (1) approval of the need to develop a transmission project, (2) approval for the

[169] The standard approval process assumes need is approved by the Commission, which would not be required for a critical transmission infrastructure project.

construction and operation of the transmission facility and (3) approval to include the costs of the transmission facilities in the rates the utility charges its customers.

11.1.3 Need

364. It is the responsibility of the AESO to identify when new transmission facilities are needed and to bring an application to the Commission for approval of the need for those new transmission facilities.[170] If need is approved, the AESO directly assigns the project to a TFO with instructions to apply to the AUC for a permit and license to construct and operate the transmission facility under the *Hydro and Electric Energy Act*, RSA 2000, c. H-16.

365. Because of the AESO's role as a neutral, not-for-profit entity,[171] AESO need applications are granted a legislative rebuttable presumption of correctness.[172] This legal presumption has shifted the previous onus from for-profit applicants to demonstrate a project was needed, to rate payers. Rate payers must satisfy the Commission that the need application submitted by the AESO is technically deficient or not in the public interest.

366. At the need approval stage, the Commission's role is to approve the actions proposed to be taken by the AESO. For a need-initiated transmission project, the Commission grants approval to the AESO to direct a TFO to apply to build the transmission facility based on the approved need. The approval also signals the Commission's general acceptance of the expected costs of the proposed solution to the approved need, including the expected reasonable and prudent expenditures incurred by the TFO to fulfill the approved need. At this stage, the AESO, pursuant to ISO Rule 9.1.2.2, includes an estimate of costs that have been prepared by the TFO with an accuracy tolerance of plus or minus 30 per cent of the final costs.

367. Approval of this action is not, however, an approval of actual expenditures and does not allow the inclusion of any imprudent expenditures in rates to be collected from customers.

11.1.4 Facility approval – permission to construct and operate

368. The AESO must determine which TFO is eligible to apply to the Commission for the construction or operation, or both, of the transmission facilities for which need has been approved. The TFO in whose service territory the transmission facility is proposed to be built, is generally assigned the project.[173] The AESO then directs that TFO to bring an application under the *Hydro and Electric Energy Act* to the Commission to obtain the necessary operating permits and connection orders for the proposed transmission facilities. These facilities are commonly referred to as direct assign facilities.

369. The TFO must provide a proposal to provide service (PPS) and a capital cost breakdown of all alternatives with an accuracy tolerance of plus 20 per cent and minus 10 per cent of the final costs for the PPS as provided for under ISO Rule 9.1.2.4. This is generally included as part of the facility application filing.

370. Section 17 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, requires the Commission to consider whether the proposed facility is in the public interest, having regard to

[170] Section 34 of the *Electric Utilities Act.*
[171] Section 9(6) and Section 14(3) of the *Electric Utilities Act.*
[172] Section 38 (e) of the *Transmission Regulation.*
[173] Section 24 of the *Transmission Regulation.*

the social, economic and environmental impacts of the proposed facility.[174] The Commission described its public interest mandate as follows in Decision 2009-028[175] at paragraph 33:

> 33. In the Commission's view, assessment of the public interest requires it to balance the benefits associated with upgrades to the transmission system with the associated impacts, having regard to the legislative framework for transmission development in Alberta. This exercise necessarily requires the Commission to weigh impacts that will be experienced on a provincial basis, such as improved system performance, reliability and access, with specific routing impacts upon those individuals or families that reside or own land along a proposed transmission route as well as other users of the land that may be affected. This approach is consistent with the EUB's historical position that the public interest standard will generally be met by an activity that benefits the segment of the public to which the legislation is aimed, while at the same time minimizing, or mitigating to an acceptable degree the potential adverse impacts on more discrete parts of the community. [footnote removed]

371. As the need or justification for the transmission facility has already been determined, including approval of a directional cost estimate, the Commission's role in the facility application context is to decide upon the location of the facility, while weighing the benefits of the project against the impacts that remain after the impacts have been mitigated, where possible. In considering the route, the Commission takes into account cost information when comparing alternatives, however, the exercise is largely one of technical (physical), not economic, regulation. Again, the Commission looks at the PPS estimates. However, facility approval does not guarantee that imprudent or unreasonable expenditures will be included in rates.

372. Under ISO Rule 9.1.2.5, the TFO must provide an update of its PPS cost estimate to the AESO on or before 180 days from the date that the Commission has issued all permits and licenses for the proposed transmission facilities. This update must have an accuracy tolerance of plus or minus 10 per cent of the final project costs.

11.1.5 Rates charged to customers

373. The rates of Alberta TFOs are not charged directly to customers but rather to the AESO, who, in turn, flows the cost of TFO rates to either directly connected industrial customers or to regulated distribution facility owners through its tariff.[176] Further, the AESO, and not the TFO, is responsible for planning and bringing forward need applications for new transmission facilities, and the TFO must respond to the direction of the AESO to construct new facilities when asked, unless doing so would put its facilities or the safety of the TFO's employees or the public at risk. The TFO includes an aggregate capital addition estimate when it develops its revenue requirement forecast for its transmission tariff and the Commission is responsible for approving the tariff that the TFOs propose to charge to the AESO for the use of their transmission facilities.

374. The tariffs of most TFOs are set prospectively by relying on forecasts of revenue required to provide utility service. Within TFO tariff applications, the TFO will normally forecast the capital investment amounts it will require for the construction of assets to provide transmission service. These amounts are trued-up to reflect actual costs when the actual costs are known –

[174] Section 19 of the *Hydro and Electric Energy Act* establishes the power of the Commission to alter, approve or deny any application for approval, permit or licence.
[175] Decision 2009-028: AltaLink Management Ltd., Transmission Line from Pincher Creek to Lethbridge, Application No. 1521942, Proceeding ID. 19, March 10, 2009.
[176] Section 37 of the *Electric Utilities Act.*

after the investments have been made and the facility is in service, and to the extent the investments are considered prudent.

11.2 Cost accountability

375. Commission approval of the prudence of transmission project costs is sought after the investments have been made and the facility is in service. The current procedure is largely a backward-looking, after-the-fact assessment for future rate-making purposes with the consequential difficulty of denying a major investment after the investment has occurred. Current regulatory procedures do not contemplate a forward-looking analysis with respect to prudence reviews during the construction cycle. Although the TFO provides change orders[177] to the AESO as required by ISO Rule 9.1.3.4, it appears that, in some instances, the AESO has indicated an acknowledgement rather than an express approval of the change described in a specific change order.[178]

376. Further legislative direction is provided under the *Transmission Regulation* as it pertains to the recovery of costs for transmission projects. Section 25(1) permits the AESO to develop rules regarding cost reporting, while Section 25(3) expressly confirms that the TFO must demonstrate that its tariff is just and reasonable and that the Commission retains responsibility to determine a TFO's or other person's prudence in managing a transmission facility project. The Commission is restricted by Section 25(5) of the *Transmission Regulation* from requiring the AESO to comment on the TFO's prudence in managing a transmission project. Instead, the AESO, who is the only entity that is receiving and reviewing cost estimates and cost variances in real time, has the legislative discretion, pursuant to Section 25(5) of the *Transmission Regulation*, to notify the Commission of any concern or issue that the AESO has with respect to the costs of a transmission project.[179]

377. As well, until July 25, 2013, Section 46(1) of the *Transmission Regulation* required the Commission to consider the majority of transmission costs incurred by the TFO to be prudent, unless an interested party satisfied the Commission that the costs were unreasonable. These stakeholders, and not the TFO, had to demonstrate that the costs captured pursuant to Section 46 of the *Transmission Regulation* were imprudent, and the Commission was required to exercise forbearance unless an interested party has demonstrated that these costs were unreasonable.

378. Effective July 25, 2013,[180] the government passed an amendment to Section 46(1) of the *Transmission Regulation* which removed the presumption of prudence for project costs incurred by the TFOs. With the removal of this presumption, TFOs must demonstrate the prudence of the costs they have incurred for these transmission projects. The presumptions of correctness with regard to the need for a transmission project, and with regard to costs paid to landowners for access, were unaffected by the change to the *Transmission Regulation* and continue to operate.

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[177] A change order is a "project change proposal" required to be submitted to the AESO by a TFO to address a delay, cost trend or scope change if there is a variance in the project beyond the limits specified in ISO Rule 9.1.3.2.

[178] See for example Exhibit 224.01, PDF page 14 of 894, and Exhibit 230.02, PDF pages 3 and 19 of 63 (copy of change orders with "approved" stroked out and "acknowledged" added in).

[179] Exhibit 176.01, PDF page 3 of 9. On March 13, 2012, the Commission received notification from the AESO pursuant to Section 25(5)(b) of the *Transmission Regulation* that certain ATCO Electric projects had exceeded the accuracy tolerances in their PPS. The AESO was clear in its letter that it was not commenting on the prudence of the revised budgets. This was the first time the AESO had sent such a notification to the Commission.

[180] Alberta Regulation 145/2013.

379. Notwithstanding this recent legislative amendment, the legislative provisions establish an environment that is not all that dissimilar from the environment that existed during the PUB/ERCB period referenced above. The legislative provisions which reversed the onus on applicants to interested parties at the need stage, creates a functional division between the entity that is determining need, effectively the AESO, and the regulator who must approve the costs. The concerns that arose in the late 1980s, such as building in advance of need or where forecasted need has not materialized, are similar to the concerns identified in this proceeding by the ratepayers today.

380. The regulatory construct of approving expenditures after the fact provides little or no opportunity for the Commission to manage the expenditures by, for example, continuously evaluating the construction program while it is in progress, by ensuring construction takes place as efficiently as possible and by ensuring any construction changes are managed in an efficient and timely manner. It is apparent to ratepayers, TFOs, the AESO and the Commission that the current process is unsatisfactory, as evidenced by the number of initiatives that are either ongoing or in development, to address the oversight and recovery of transmission capital project costs.

381. Some of these parallel initiatives, many of which have been identified by the interveners and by ATCO Electric in this proceeding, include:

- Transmission Facilities Cost Monitoring Committee (TFCMC) review: The TFCMC was established by Ministerial Order 64/2010 pursuant to Section 7 of the *Government Organization Act*, RSA 2000, c. G-10, on July 31, 2010. Its mandate, as set out in the ministerial order, is to (1) review records that relate to the cost, scope, schedule and variances of transmission facility projects that are forecast to cost in excess of $100.0 million; (2) prepare reports that summarize the records it reviews and the status of the transmission facility projects; (3) provide at least two reports to the organizations represented on the TFCMC each calendar year; (4) provide at least one report to the ministers of Energy and Service Alberta each calendar year; and (5) not delay or slow the development of transmission facility projects.

- AESO Cost Accountability Consultation (ISO Rule 9.1.2 review): In January 2013, the AESO held an industry workgroup meeting with the objective of reviewing ISO Rule 9.1.2 to improve the quality and accuracy of cost estimates.[181] This work is ongoing.

- Transmission Project Reporting Oversight Protocol: In August 2012, the AESO issued a recommendation paper in which it described its intention to work with the Commission to develop a reporting and oversight protocol for transmission projects. This work is ongoing.

- Electric Transmission Cost Recovery Alternatives, Proceeding ID No. 2421: On June 14, 2013, following a Commission-led stakeholder conference, the Commission issued Bulletin 2013-17.[182] In its bulletin, the Commission identified five objectives for the examination of alternative approaches and rate treatments for transmission cost recovery. This proceeding is ongoing.

[181] Copies of the presentations and other materials can be found on the AESO's website under Cost Accountability Consultation.
[182] Bulletin 2013-17, Electric transmission cost recovery alternatives, June 14, 2013.

- Legislative changes: On July 25, 2013, the government passed the *Transmission Amendment Regulation*, AR 145/2013 repealing Section 46(1)(a) of the *Transmission Regulation*.

- Government sponsored dialogues such as the Electricity Coordinating Forum and Market Advisory Committee.

382. In this proceeding, the interveners have proposed recommendations regarding transmission project design, ISD forecasts, project prioritization and the need to determine cost accountability in real time (cost and performance audits). The interveners have made these recommendations, understanding that this GTA may not be the forum to address all of the issues they have proposed. However, in the interests of timing, they have submitted that this is the most expedient forum.

383. Their concerns were expressed by the RPG as follows:

> A. MR. LEVSON: Well, I think there's value in both -- in both aspects of that. If you're talking about the formal side where somebody has to sign a document and take ultimate responsibility, yes, we can't have two people building transmission lines. But when it comes to what we're trying to advocate here is a cooperation, a level of cooperation that we used to see -- we won't mention that word -- but that we used to see that we would like to see again, and we feel is essential for the proper management of these projects. So we'd like to see both the TFOs and the AESO taking cost responsibility for these projects and dialoguing with each other in such a way that they -- that we will get the lowest cost options made available to us as customers.[183]

> A. MR. LEVSON: Potentially working with AltaLink, but there's no reason why any TFO who identifies a problem with a standard or a project or anything that can't go to the AESO and work out something with that -- with the AESO for that project. So we don't need to turn -- there's an urgency that we have here on these projects. If we wait two, three, four years for sort of normal processes, you know, several billion dollars will have been spent and it will all be history. So I think we have a sense that we need to move quickly with the projects where we see some opportunities for savings.[184]

> A. MR. LEVSON: It's -- I think it's obvious that the AESO sets the ISDs. I guess we're here partly in front of this Commission because we feel like the system is broken, and I guess we're asking the AUC to intervene and to conduct -- initiate a process or direct a process, and I'm

[183] Transcript, Volume 8, page 1589, lines 1-14.
[184] Transcript, Volume 8, page 1608, lines 19-25; page 1609, lines 1-4.

not necessarily talking about a hearing process. I don't know that that's necessary, but these parties need to get together we think with some clear direction from the AUC to identify what are the priorities.
And there may be nobody in the AESO who is willing to make the tough call that used to be made, which is the A projects go ahead, the Cs get cut, and somewhere along in the Bs, something has to happen. And it might be that the AUC -- they might need to come to the AUC and get some direction, and maybe the AUC needs to assist the AESO with this difficult decision. That's I guess kind of what we're -- roughly what we're thinking.[185] [underlining added]

A. MS. BELLISSIMO: I think I understand your question. I think a lot of what we have been saying in this proceeding or at least in this part of the hearing is what we see is cracks all over the system and all over the responsibilities, and no one else is stepping up. There's been a significant trust deficit that's developed between consumers and everyone else in the electricity sector, including the AESO, TFOs, and everyone else, including the DOE, everyone who is responsible for making decisions on our behalf.
Customers are going to be spending an awful lot more money than they ever have before on electricity transmission. Costs will be more than doubling between 2011 and 2014. These are huge costs. And no one is advocating for us, and no one is taking our advocacy seriously. So we have tried everyone else, and that's why we're here with you.[186] [underlining added]

384. The Commission agrees that it is important to respond to the concerns raised by the interveners in a timely fashion. Notwithstanding the ongoing processes referenced above and given the regulatory approval structure outlined in this section, the Commission has addressed the recommendations of the interveners regarding project prioritization, ISDs, project design and functional specifications and cost audits in this proceeding. Commission specific directions regarding the forecast capital projects included in this application over the test period are included in Section 11 and in Section 17 of this decision.

11.3 Project priorities, system planning and in-service dates

385. ATCO Electric and the interveners both agree that system planning is the responsibility of the AESO. Notwithstanding, the RPG has recommended that the Commission direct ATCO Electric to work with the AESO to review and prioritize its direct assigned capital projects in order to ensure that these capital projects are developed in a manner that minimizes costs while still meeting safety and reliability requirements. At a minimum, the RPG has requested the Commission to direct ATCO Electric to conduct this type of planning process for

[185] Transcript, Volume 8, page 1642, lines 9-25.
[186] Transcript, Volume 8, page 1710, lines 13-25; page 1711, lines 1-3.

the five most costly projects proposed over the test period, with the objective of reducing the overall costs of development during the test period.[187] Specifically, the RPG's witnesses stated:

> A. MS. BELLISSIMO: There is a problem with regards to resourcing intervener groups, customer groups to participate in these processes. So if we were to go and participate in one individual need application, it would be tremendously resource draining. However, if we were to participate in an organized fashion to examine all of the in-service dates and all of the project prioritizations through an organized mechanism, that would be much more achievable. So similar to how we're able to participate in the transmission facilities cost monitoring committee. It's a structure that would work, and I think it would be very necessary to have ratepayer representation at this type of project prioritization. It would be much more accessible to do it en masse.[188] [underlining added]

> A. MR. LEVSON: Maybe I'll just add that right now the status quo is that we're not at the table, and so the people that pay the bills are left out of the decision. And so my -- it is speculation, but my sense is that customer groups probably won't be disagreeing that much among ourselves. This isn't like a cost-of-service allocation exercise. It's more -- and I guess I'm assuming that what we have said earlier, that the A class projects and the interconnection projects are one and the same, and it's really some of these bulk system projects where the opportunities are; and there's no customer class, individual customer class that's going to be harmed by this. So I guess that rolls into our -- informs us, that assumption, I guess. So, yes. Like, we need to be fair to all customer groups, but I don't anticipate that that would be a big problem. And the other thought I had is that this is ultimately still the AESO's call. They still get to, you know -- they still have the accountability for the ISDs on these projects. So we're just looking for an avenue to get some influence on this process which we don't have right now.[189] [underlining added]

386. ATCO Electric has responded to this recommendation by explaining that it is already constantly working with the AESO to develop reasonable and executable ISDs. Examples of this ongoing work include the monthly progress reports that are provided to the AESO for all direct assigned capital projects over $1.0 million and the reports required to be filed by ATCO Electric to the AESO under ISO Rule 9.1.3. Further, ATCO Electric has recognized that forecasting for direct assigned capital projects can be improved and it has made adjustments to its project schedule and forecast ISDs in conjunction with the AESO. Given this ongoing activity, ATCO

[187] Exhibit 238,01, RPG argument, Volume 1, page 3.
[188] Transcript, Volume 8, page 1644, lines 11-24.
[189] Transcript, Volume 8, page 1648, lines 24-25; page 1649, lines 1-18.

Electric does not consider further direction from the Commission, as recommended by the RPG, to be necessary.

387. The Commission has heard evidence that ATCO Electric has proactively been in discussions with the AESO regarding project ISDs. However, the Commission understands the issue for rate payers to be that they do not have a venue in which to participate in the process and that they are unsatisfied with the results that have been produced by the current approach that ATCO Electric and the AESO have used as the context for these project prioritization discussions.

388. As set out in ATCO Electric's evidence, it is already consulting with the AESO so there is no need for the Commission to direct ATCO Electric to do what it is already doing and what the Commission expects it will continue to do. Notwithstanding, the Commission considers the approach advocated by the RPG to include rate payers in the process, and to plan transmission on the basis of overall project prioritization, to have merit. However, as set out in Section 17 of the *Electric Utilities Act* and Part 2 of the *Transmission Regulation,* system planning is clearly the responsibility of the AESO. Consequently, apart from encouraging the AESO to consider this approach, the Commission cannot direct the AESO to engage in this process.

11.4 Project design and functional specifications

389. The RPG has proposed several recommendations with regard to transmission facility design and selection, including the impact of ISO Rule 502.2 on these decisions, which is addressed in Section 11.8.3 of this decision. In addition, the RPG has requested that the Commission direct ATCO Electric to proactively engage with the AESO in an iterative planning process to develop additional tower designs that are economical and suitable, and to avoid building transmission facilities that are not least cost. Specifically, the RPG witnesses stated:

> there's a difference between accountability and responsibility. The AESO may produce the final result or the outcome as a standard, but the TFOs are the designers, builders, and operators of the transmission lines in the province, not the AESO. They have the expertise on transmission line design, and they will be building these lines on an ongoing basis. Our expectation would be that the TFO would play a major role in any standard that is developed with regards to the construction of transmission lines.[190] [underlining added]

> appropriate? And I would hold the TFOs accountable to act as the transmission line designer and provide expert advice to the AESO with regards to what's required.
> A. MR. LEVSON: So just so part of the problem is to get to your issue, which I understand, I think is that the costs are here, and the -- you know, the standards are in another organization. And so how do we bring these together? That's the challenge. It's easy to write a standard and say, "yeah, we're going to solve all the world's problems," and every wet snow condition, you know, they could ever imagine, and then suddenly the cost lands somewhere else. And so

[190] Transcript, Volume 8, page 1613, lines 1-10.

> we're chasing the costs, tracing them back to the root cause. And this is where we're starting. And obviously the TFCMC and other people have raised some alarm bells on this with the AESO. This isn't, you know, happening here without anybody's other involvement, but we just see the TFOs as very well positioned to assist the AESO on the cost implications of this. You're seeing the costs. That they need to go back to the AESO with some options rather than we're just doing what we're told to do. That's not acceptable from our point of view.[191] [underlining added]

> But I think -- yeah, I think my answer is yes, it would be expected as what would be typical best practice in the industry if you want to end up with the lowest overall cost. Whether or not the AESO would interpret it that way, this gets into the issue around who has the expertise. You know, the AESO is the, you know, system planner, system operator. They don't build transmission lines. They don't do transmission line design, so I think they're pretty limited with regards to their knowledge on this, and they would be trusting the TFO.[192] [underlining added]

390. ATCO Electric responded to this recommendation, in its rebuttal evidence, by explaining that it presently utilizes a suite of structures that are the most economical to use in the various circumstances that it encounters, that it cannot be faulted for complying with the ISO design rules and that, by utilizing a limited suite of structures and conductor types, this reduces overall engineering and development costs and ensures stability in O&M practices. Further, ATCO Electric indicated that it has continuously participated in the various generic processes that the AESO has conducted within the AESO's mandate, and that this is not the forum to discuss and debate these issues.

391. Issues of design fall within the jurisdiction of the AESO and the Commission understands that the AESO engages in consultation with stakeholders when it proposes new ISO rules or changes to existing ISO Rules. However, the Commission also understands that the AESO has primarily acted as the system planner, and within this role has relied primarily on the TFO's expertise and input regarding optimal transmission line design. The Commission agrees that the TFOs should proactively discuss design and functional standards with the AESO and, to the extent that the TFOs have considerable expertise in this area, they have a duty to make recommendations to the AESO that reflect the interests of customers and that avoid needless expenditures. Similarly, the Commission considers that it would be desirable to include the input of rate payers in the process as well where circumstances warrant. However, pursuant to Section 17 of the *Electric Utilities Act* and Part 2 of the *Transmission Regulation,* apart from encouraging the AESO to consider this approach, the Commission cannot direct the AESO to engage in this process.

[191] Transcript, Volume 8, page 1614, lines 1-22.
[192] Transcript, Volume 8, page 1661, lines 1-10.

392. Whether the design selected and implemented, and the resultant costs that flow from the exercise of that discretion by the TFO, have resulted in prudent costs being incurred, is a matter that will have to be determined by the Commission in the direct assigned capital projects deferral account proceeding before the costs of the project can be recovered in rates.

393. The prudence test developed by the Commission's predecessor, the EUB, was approved by the Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)* 2005 ABCA 122. Decision 2001-110[193] was the decision under appeal and the prudence test set out in Decision 2001-110 has been relied on in several decisions by the EUB and the Commission since that time and bears repeating:

> The Board will set out its general views on prudence in this section.
>
> In Decision 2000-01, in the context of an application by an electric utility, the Board noted that:
>
> > In most cases [prudence] involves an evaluation of whether or not a decision reflects good judgement and discretion and is reasonable in the circumstances which were known, or reasonably should have been known, when the decision was made.
> >
> > The concept of prudence is used to determine whether, at a particular time in question, an arrangement is or was appropriate and reasonable given the circumstances known or which ought to have been known.
>
> The Board earlier applied this test in the context of a prudence review for gas utilities in Decision E95079, concerning Nova Gas Transmission Ltd. In that decision the Board determined that, in addition to the usual concept of prudence, additional elements could be part of the prudence standard to address the particular circumstances at hand.
>
> The Board considers that there are particular circumstances to consider when assessing the prudence of actions carried out by the owner of a public utility. Given the unique relationship between a public utility and its customers, the Board believes there is an additional element to consider in a prudence review. The Board agrees with the CCA that a prudent owner of a public utility must not only exercise good judgment and act in a reasonable and appropriate manner, but must do so in light of a duty to act in the best interests of its customers, while being entitled to a fair return on its capital and a return of its capital**.**
>
> The Board agrees with ATCO that a prudence review ought not to be based on hindsight. Webster's Dictionary defines hindsight as "perception of the nature and demands of an event after it has happened." Applying this definition to the current context, the Board ought not to impute knowledge to the owner of a utility that the owner of the utility could not reasonably have known at the time the utility made the decision being reviewed. The Board notes that two American public utilities commissions have also held that a prudence review should not be made on the basis of hindsight.

[193] Decision 2001-110: Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding, Part B-1: Deferred Gas Account Reconciliation for ATCO Gas, Application No. 2001040, File No. 5680-1, December 12, 2001.

> In summary, a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take into account the best interests of its customers, while still being entitled to a fair return.[194] [underlining added] [footnotes removed]

394. The Court of Appeal stated in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)* 2005 ABCA 122 as follows:

> **72** The Board's broad discretion to set just and reasonable utilities rates must be exercised in the public interest, which requires consideration of both sides of the rate paying equation: ATCO Electric, supra at 132. That process implicitly entails scrutiny of management decisions. With respect to negotiated settlements Fraser C.J.A. held in ATCO Electric at para. 145 that the Board "is entitled to assume that what the utility has negotiated and agreed to is in fact in the utility's best interests." However, in the context of rate setting, the starting point for scrutinizing management decisions is the presumption that it is in the utility's interest to make prudent decisions which also reflect the interests of its customers, by avoiding needless expenditure. That presumption will matter only when the scales are evenly balanced.
>
> **73** In this case, in determining to uphold ATCO's decision unless satisfied ATCO had acted unreasonably, the Board correctly acknowledged the presumption of prudence. The test it articulated to be applied in reviewing the prudence and reasonableness of ATCO's decisions is reasonable.

395. The factors identified by ATCO Electric in support of their actions, such as compliance with ISO rules, and utilizing a limited suite of structures and conductor types to reduce overall engineering and development costs and ensure stability in O&M practices, are all matters that will be considered by the Commission in determining the prudence of ATCO Electric's costs for specific capital projects in subsequent deferral account proceedings. The Commission will also consider whether ATCO Electric took steps to proactively discuss design and functional standards with the AESO and made recommendations to the AESO that reflect the interests of customers and that avoided needless expenditures.

11.5 Audits of transmission project expenditures

396. The RPG has proposed that customers should be granted access to information to be obtained from cost and performance audits, either directly through the establishment of the connecting customer's right to request an audit of an interconnection project, or indirectly through a Commission direction to appoint auditors with necessary engineering, construction or accounting expertise for system projects. A cost audit would test whether costs are accurately recorded in the TFO's project cost reports, business systems and general accounting ledgers. It would also ensure that costs are properly supported by source documents and that the costs were incurred in accordance with prevailing terms and conditions of existing contract documents or purchase orders. A performance audit would examine programs, functions, and operation or management systems and procedures of the TFO to assess whether the TFO is achieving economy, efficiency and effectiveness in the employment of available resources.

[194] Decision 2001-110, pages 9 and 10.

397. ATCO Electric responded to this recommendation, in its rebuttal evidence, by identifying the numerous processes currently in place that, in its view, makes these two additional audits duplicative or redundant. Specifically, ATCO Electric referenced its internal controls, its internal audit department, and the AESO and Commission audit functions that are already available. As well, the role now being played by the TFCMC in reviewing costs has also increased cost scrutiny. In its view, the issues raised by the RPG with regard to cost and performance audits are already being discussed among the AESO and the Commission and are more appropriately dealt with as a generic issue.

398. The Commission recognized in Decision 2008-076[195] a need to have some type of validation of costs on major construction projects, stating:

> The Commission considers there to be substantial merit to CG's proposal. Primarily, the CG proposal would involve some independent third party verification of the reasonableness of AltaLink's costs. The Commission appreciates that such an audit is not without problems, As AltaLink has argued, care would have to be taken to ensure that any comparisons made would have to be on an apples to apples basis. Also, there is the matter of cost. Notwithstanding these difficulties, the Commission has been asked to approve hundreds of millions of dollars in capital expenditures and on balance, does not consider it unreasonable for it, as well as the customers who ultimately pay the costs for these facilities, to have before it an independent assessment with respect to the reasonableness of these facility costs.
>
> In addition to an EPCM audit as suggests by CG, the Commission considers it would be helpful if there were greater independent scrutiny of AltaLink's project costs estimates. This would address another concern with audits, namely that they are largely after the fact. While the Commission sees merit in both a CG style audit and more scrutiny of project estimates, it will not give any direction to AltaLink at the present time. These matters can be addressed in the next GTA.[196]

399. As noted by ATCO Electric's witness, the issue of audits has been raised in the past and is currently being examined through the Transmission Project Reporting and Oversight Protocol being developed through discussions with the Commission and the AESO:

> Q. MR. WACHOWICH: Mr. DeChamplain, we're quite clear, ATCO Electric doesn't see value in the additional audits recommended by the ratepayer group; fair?
> A. MR. DECHAMPLAIN: We believe that the matters of EPCM audit or a separate independent check on estimates or actuals are best discussed as an industry through the AESO and AUC reporting protocol, as outlined by the Commission in the recently anointed Exhibit 133.04, where at the top of page 4, it says: (as read)
> "The AESO and Commission expect to consult with TFOs and other stakeholders during this development of additional reporting and oversight practices.

[195] Decision 2008-076: AltaLink Management Ltd., Reconciliation of Deferral Accounts May 1, 2004 – December 31, 2006, Application No. 1561334, Proceeding ID. 17, August 26, 2008.
[196] Decision 2008-076, pages 8 and 9.

> In my mind, this is a bit of a culmination of a process that started with the decision which you referred to, 2008-076. And then with the help of Mr. Heggie and the AUC's submission in the transmission -- sorry, the AESO's review of 9.1, there's a submission in there that outlines the chronology of decisions going back to 2008 the generic TFO, Ts and Cs, 2009-151, AltaLink's 2009 and '10 GTA; Decision 2010-284, AltaLink's 2007-2008 DACDA, D-A-C-D-A, process; again, in Decision 2011-122, AltaLink's 2009 DACDA process; most recently in AltaLink's 2011-2013 GTA in Decision 2011-453, where the Commission has reaffirmed its intention to develop a cost control reporting rule with broad consultations, and interveners have been advised repeatedly to bring their recommendations there. Hopefully this October 2012 reporting and oversight protocol will -- will get some traction, and we'll be able to put this to bed as an industry.[197]

400. Notwithstanding this ongoing process, it was also acknowledged by ATCO Electric's witness that it is unlikely that the process will be completed before this proceeding concludes:

> Q. MR. WACHOWICH: But as far as we know, sir, that is the last direction we have from this Commission as to what we should be bringing into the GTA process. So let me put it to you this way, Mr. DeChamplain: You now seem to have given heightened importance to the AESO and AUC protocol, but you recognize, sir, that's not yet complete?
> A. MR. DECHAMPLAIN: Yes, sir.
> Q. Will it be complete by December 12th, sir, when you suggested earlier that this record may close?
> A. MR. DECHAMPLAIN: Highly unlikely, sir.
> Q. Okay. So it's highly probable the Commission intends us to take the course of action of examining these types of issues within a context of a GTA for a TFO under its jurisdiction; fair?
> A. MR. DECHAMPLAIN: Yes. And as with the AltaLink GTA, the Commission reaffirmed its intention agreeing with AltaLink that broad consultations would be of benefit before it proceeded with the implementation of changing the rules of the game.[198]

401. The Commission remains interested in the potential for significant improvements to cost reporting and oversight processes to be adopted through the further development of the Transmission Project Reporting and Oversight Protocol discussed above. However, given the magnitude of the capital expenditures described in the application, the Commission is of the view that there may not be sufficient time to wait for the full development of the oversight protocol before taking action on certain transmission projects. As a result, where the Commission has determined that the project costs or other considerations in respect of a specific

[197] Transcript, Volume 4, page 849, lines 8-25; page 850, lines 1-13.
[198] Transcript, Volume 4, page 851, lines 16-25; page 852, lines 1-10.

project identified in a GTA requires further investigation, either through a form of audit or other investigation, the Commission will issue directions to this effect prior to the completion of the Transmission Project Reporting and Oversight Protocol process.

11.6 Approval of 2011 closing balances

402. In the calculation of the 2013 and 2014 forecast rate base amounts, ATCO Electric included actual amounts for the year 2011 and forecast amounts for the year 2012. Other than the actual additions to rate base for 2011 for the direct assigned capital projects, which are included in the direct assigned capital projects deferral account, ATCO Electric's request for approval of the remainder of the 2011 actual additions has been addressed in this section of the decision. Parties did not raise any issues regarding these additions.

403. These remaining actual capital additions to rate base for 2011, along with the approved forecast amounts, are detailed in the following table:

Table 19. Remaining actual capital additions for 2011 compared to approved forecast

	Actual	Forecast
	($ million)	
Capital maintenance	59.7	58.8
Isolated generation	4.7	15.0
Allocated direct general	7.9	7.3
Allocated software	0.5	0.1
Allocated buildings	12.7	6.9
Allocated general	2.8	0.5
Total	88.3	88.6

Sources: Actuals – Exhibit 188.02, Schedule 10-4. Forecast – Proceeding ID 1241, Exhibit 3 (Schedule 10-4); Exhibit 9 (worksheet entitled Schedule 10-4).

404. The explanation provided by ATCO Electric for the $10.3 million variance for isolated generation costs was mainly attributable to Project 90143: replacement of the turbine at the Jasper palisades plant. ATCO Electric had forecast $9.5 million to be added to capital in 2011; however, this project was not completed in 2011. The project is now expected to be completed in 2012 at a forecast cost of $14.9 million. ATCO Electric provided more information about this in response to information request AUC-AE-023(a).[199]

405. The $5.8 million variance for buildings is comprised mainly of actual additions of $6.9 million for Project 85046 (Vegreville land development) and $3.3 million for Project 85047 (Vegreville equipment requirements), partially offset by a variance of $5.5 million for Project 85821 (Nisku warehouse renovation), because the Nisku warehouse renovation was not completed in 2011 as forecast. The scope of the Nisku warehouse project has since been expanded and was forecast to be completed in 2012 at a cost of $8.3 million.

406. The two Vegreville projects were not included as part of ATCO Electric's 2011 forecast and details for the projects, including the business cases for these projects, were not provided until requested as part of an undertaking.[200] ATCO Electric bears the onus for justifying capital

[199] Exhibit 50.01.
[200] Exhibit 149.01.

additions. Providing business cases for any significant capital project is a minimum requirement in any GTA in discharging this onus, and the Commission should not have to request such business cases during the course of an oral hearing.

407. The business case for Project 85046, included an executive summary, which included the following description of the project:

> This business case evaluates the drivers, costs and benefits associated with developing 32.7 acres of land at ATCO Electric's Vegreville facility to provide material storage and staging for capital projects.[201]

408. As noted in the business case, the justification for developing and expanding the Vegreville facility and lands is dependent on the large transmission capital expansion program that is currently underway in Alberta. This type of use could be temporary in nature and the Commission reminds ATCO Electric that it is responsible for ensuring that any capital property that is no longer required for the provision of utility service be removed from rate base.

409. The Commission directs ATCO Electric, as part of its next GTA, to provide an update on the expected future use of the Vegreville land, but otherwise approves these 2011 rate base additions as filed, subject to any future adjustments that may arise as a result of the true-up of any placeholders.

11.7 Approval of 2012 closing balances

410. As the release date of this decision is well after the end of 2012, the Commission finds it necessary for ATCO Electric to update the calculation of the mid-year net rate base forecast for 2012, included in the omissions and updates filing, to reflect the actual results for 2012, and directs ATCO Electric to provide such an update in the compliance filing. This update will allow the actual capital project results for 2012 to be incorporated and factored into the calculation of the revenue requirements for the years 2013 and 2014.

11.8 2013 and 2014 forecast capital expenditures and additions

411. ATCO Electric has separated its capital projects into two categories: direct assigned and non-direct assigned. As noted previously in this decision, direct assigned capital projects are those that are directly assigned to ATCO Electric by the AESO. Non-direct assigned capital projects are those that are not included in the direct assigned category.

412. ATCO Electric further subdivides its non-direct assigned capital projects into the following categories:

- capital maintenance
  - general
  - telecommunication
  - Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS)
- isolated generation

[201] Exhibit 149.01, page 4 of 10.

- allocated share of direct general property, plant and equipment (PP&E)
- allocated share of software
- allocated share of buildings
- allocated share of general PP&E

413. The forecast amounts for 2013 and 2014 included in the supplementary revenue requirement schedules[202] that were filed in conjunction with the omissions and updates filing are as follows:

Table 20. Forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
	Expenditures	Additions	Expenditures	Additions
	($ million)			
Direct assigned	1,407.4	1,361.9	1,082.3	2,028.1
Non-direct assigned				
Capital maintenance				
General	68.9	86.0	65.0	74.6
Telecommunication	18.6	18.4	19.8	26.4
SCADA/EMS	2.2	2.2	2.9	2.9
Total capital maintenance	89.7	106.6	87.7	103.9
Isolated generation	6.7	3.2	4.2	8.1
Allocated direct general	9.5	9.5	12.2	12.2
Allocated software	8.5	11.8	6.3	6.3
Allocated buildings	12.9	9.6	4.9	11.0
Allocated general (Note 1)		4.2		1.3
Total non-direct assigned	127.3	144.9	115.3	142.8
Net salvage	-	(1.4)	-	(2.0)
Total	1,534.7	1,505.4	1,197.6	2,168.9

Note 1: No breakdown of the capital expenditure amount between transmission and distribution was provided. The total combined capital expenditure forecast is $9.4 million in 2013 and $3.2 million in 2014.

11.8.1 Adequacy of business cases

414. ATCO Electric stated in paragraph 183 of its application that: "Information supporting the capital expenditures is provided in the Transmission Business Cases section."

415. The following information is included under "Business Cases" in the MFR document that is posted on the Commission's website.

> **Business Cases**
>
> Applicants shall provide business cases for capital projects and programs in excess of $500,000 (Smaller applicants with revenues less than $100 million, excluding the cost of

[202] Exhibit 188.02.

energy will be subject to a materiality limit of $100,000) 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; and
- The date of preparation and the date of approval.

416. The Commission finds that the number and overall quality of the material in the business cases that were provided by ATCO Electric in support of its forecast capital projects was generally inadequate. In some cases, business cases were not provided at all and as an example of the deficiencies in quality, the Commission notes that ATCO Electric provided an undated, one page executive summary for a project with a cost of $7.3 million. Additional detail was not provided until ATCO Electric was asked to do so. For many projects, a lot of relevant and necessary information that should have been included in the business case was provided subsequently through the submission of responses to information requests from the interveners and the Commission. The MFR are just that. The Commission expects ATCO Electric to provide business cases that comply with these minimum requirements and that provide sufficiently detailed information to fully explain and support the capital projects to which they apply. As stated previously, ATCO Electric bears the onus to justify its tariff application, and the Commission should not be required to request basic relevant information with respect to capital projects during the processing of the application that should have been provided with the initial application.

11.8.2 Non-direct assigned capital projects

417. ATCO Electric explained that its non-direct assigned capital projects are determined by inspecting, testing and studying the condition and functional condition of its assets. Projects are subsequently bundled and aligned with other maintenance activities or direct assigned capital projects to ensure work is performed in a cost effective manner. As well, because detailed scope, engineering and costs estimates for annual programs are typically completed in the year prior to execution, ATCO Electric's forecast is determined from preliminary scope definition and historical actual information for similar projects.

11.8.2.1 Capital maintenance

418. Capital maintenance encompasses projects where transmission assets that are obsolete, insufficient, faulty or worn are being replaced, and the capital maintenance program is used to efficiently and economically manage capital assets and their performance through their life-cycle. Capital maintenance is further divided into three sub-categories: (1) general, (2) telecommunication, and (3) SCADA/EMS.

Discussion of issues

419. The RPG considered capital maintenance to be an area of work in which utilities have some latitude with regard to the timing and replacement of facilities and equipment. In light of

ATCO Electric's assertion that it is operating under considerable Alberta economy-wide construction pressures, which include labour market shortages and vendors operating with insufficient resources, the RPG recommended that ATCO Electric be directed to review and prioritize its major capital maintenance projects. ATCO Electric and the AESO should work together on a thorough review of the priority of projects to identify system and customer priorities and to re-evaluate ISDs. The goal of this review would be to identify those projects that could be deferred without appreciable harm to system reliability or to customer service.

420. The RPG recommended that the capital expenditures for the entire capital maintenance area be reduced to $84.4 million over the two-year test period, and that ATCO Electric be directed to prioritize equipment replacements within the confines of a disciplined budget. By restricting the capital maintenance spending, the RPG asserted that a more aggressive prioritization of equipment replacements will be required and more innovative solutions will result.

421. ATCO Electric replied that in many cases it has explicitly evaluated the option to do nothing during the test period, and it has rejected this option, based on the condition of its existing equipment and the risk to safety and reliability that such inaction presents. For the capital maintenance projects, ATCO Electric further asserted that it has presented all solutions considered and the reason for adopting its selected solution in its business cases, and it indicated that the RPG did not suggest that ATCO Electric had failed to identify any innovative solutions in its business cases.

422. ATCO Electric further indicated that although the AESO does not direct its capital maintenance programs, it does consult with the AESO where necessary, respecting both the timing of, and need for, capital maintenance, and it referred to several specific examples of such consultation. It added that capital maintenance projects rely on internal resources and more specialized niche contractors, and these are not expected to experience the same skill shortages as is expected for the direct assigned capital projects.

Commission findings

423. The RPG's suggested reduction of $84.4 million for capital expenditures over the two-year test period is based on reductions with respect to each of the general, telecommunication, and SCADA/EMS areas, and the Commission has addressed each of these separately in subsequent sections of this decision.

424. In Section 11.3 of the decision, the Commission considered a similar request from the RPG to coordinate with the AESO in respect of direct assigned capital projects. Recognizing that the AESO is legislatively responsible for system planning, the Commission nevertheless indicated support for the RPG's recommendation that TFOs and the AESO work together to prioritize and coordinate their projects on a global basis, and the Commission encouraged ATCO Electric and the AESO to do so. As ATCO Electric has indicated that it already consults with the AESO respecting the timing and need for capital maintenance projects, the Commission does not consider it necessary to further direct ATCO Electric to do what it is already doing. The Commission expects that ATCO Electric will continue to consult with the AESO regarding its capital maintenance projects and will do so in consideration of the best interests of its customers, and with the objective of avoiding needless expense. The Commission would like further information regarding these consultations and accordingly directs ATCO Electric to provide a report, as part of its next GTA, describing the consultations that it has engaged in with the AESO

regarding its capital maintenance projects and outlining the outcome of these consultations in respect of the capital maintenance projects it has proposed.

11.8.2.2 Capital maintenance – general

425. ATCO Electric's capital maintenance programs are intended to address concerns related to safety and the environment and to manage the life cycle costs of its transmission assets. ATCO Electric forecast its capital maintenance costs to increase over historical levels due to the condition and performance of older assets needing to be addressed during the test period. All of the projects in this category are a continuation of projects and programs that have been included and approved in previous GTAs, with the exception of Project 50041, which is a new project for the 2013-2014 test period. The latest forecast is as follows:

Table 21. Capital maintenance – general: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
50010: Capital maintenance - substations	6.7	5.5	7.1	6.7
50020: Capital maintenance - lines	8.2	5.2	8.0	14.5
50040: System right-of-way	2.9	2.9	3.3	3.3
50041: System right-of-way widening*	7.0	7.0	5.7	5.7
50060: Substation rebuilds	14.1	20.7	16.7	22.5
50130: Replace or rebuild major apparatus	4.4	3.8	4.7	4.4
50170: Emergency apparatus	2.7	5.7	2.3	0.3
50190: Lines – ground clearance	3.9	3.9	4.3	4.3
50500: McNeill HVDC control replacement	7.5	19.5	0.0	0.0
50940: Mitigate double circuit contacts	9.8	9.8	11.2	11.2
50960: Mitigate equipment problems	1.7	2.0	1.7	1.7
Total	68.9	86.0	65.0	74.6

Source: Exhibit 188.02, Schedule 10-4.
* New capital maintenance project.

426. Within the test period, ATCO Electric plans to continue its rebuilding substations project, 50060, for those substations with major civil and structural problems resulting from aging or outdated equipment, because this condition presents a risk to system reliability and safety of the staff who work in those substations. It also plans to continue programs such as Project 50190 and Project 50940 because these are required to provide a safe environment for the public and ATCO Electric's employees, as well as to enable the transmission system to derive the benefits of the full rating of transmission lines. Completion of Project 50500 will address equipment obsolescence issues and secure the future of the McNeill station.

427. ATCO Electric included a new project, 50041, commenced in 2012, which aimed at eliminating potentially hazardous vegetation adjacent to existing transmission right of ways, particularly for older 240-kV and 144-kV transmission lines having mature timber stands with 30 years of growth.

Discussion of issues

428. The RPG made recommendations for reductions to five specific projects, those being projects 50010, 50020, 50041, 50060, and 50940. The specifics of these recommendations are as follows:

Table 22. RPG recommended reductions for capital maintenance - general[203]

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
50010: Capital maintenance - substations	3.3	2.8	3.6	3.5
50020: Capital maintenance - lines	4.1	2.6	4.0	7.2
50041: System right-of-way widening	7.0	7.0	5.7	5.7
50060: Substation rebuilds	10.1	7.5	12.0	16.0
50940: Mitigate double circuit contacts	9.8	9.8	11.2	11.2
Total	34.3	29.7	36.5	43.6

Project 50010 and Project 50020: capital maintenance – lines and substations

429. These projects include approximately 100 individual projects as well as specific programs necessary to maintain the safety and integrity of the transmission system. Every year a detailed plan for the next year is developed by analyzing data collected from various sources, including interviews and discussions with field, maintenance and engineering staff, field inspections, as well as test and condition results including age analysis. ATCO Electric included a sample engineering report as part of the business case.

430. ATCO Electric included the following general categories for the individual projects included in Project 50010 and Project 50020. ATCO Electric also provided a more detailed list of the forecast activities in these categories and indicated that a detailed analysis of individual projects and programs is completed to ensure that the business drivers, associated risks and alternatives are adequately considered. An example of an individual project analysis was provided in the application.

- System performance – projects which are required to maintain or improve system performance to an acceptable level.
- Life extension – projects which are required to restore or extend the life of apparatus or facilities.
- Replacements – projects which are required to replace or upgrade assets to restore their function.
- External requirements – projects which are required to meet ATCO Electric's obligations to external parties, which principally includes relocation of structures as requested by provincial and municipal agencies.
- System and apparatus monitoring – projects which are required to monitor and collect performance and maintenance specific data.

[203] Exhibit 238.02, RPG argument, page 6.

- Safety and environment – projects which are required to meet federal and provincial legislation and regulation as well as corporate safety and environmental policies and practices.

431. A significant cost driver in Project 50020 is the projected relocation/replacement of structures due to external requirements. Based on consultations with Alberta Transportation, ATCO Electric identified and included in the test period, estimates for several line relocation projects. The cost of these projects is partially offset by contributions.

432. ATCO Electric provided the following forecast amounts by these particular categories:

Table 23. Capital maintenance – lines and substations expenditures by category[204]

	2013 forecast		2014 forecast	
Description	**Lines**	**Substations**	**Lines**	**Substations**
	($ million)			
System performance	0.0	0.5	0.0	0.6
Life extensions	1.3	2.8	2.2	2.1
Replacements	1.8	2.3	0.9	3.4
External requirements	5.1	0.0	4.9	0.0
System and apparatus monitoring	0.0	0.6	0.0	0.8
Safety and environment	0.0	0.5	0.0	0.2
Total	8.2	6.7	8.0	7.1

433. The RPG recommended capital expenditure reductions of $7.4 million in 2013 and $7.6 million in 2014 on the basis that the average annual capital expenditures for the years 2009 and 2010 were $9.0 million, and it submitted that these reductions would make the forecast for the test period consistent with past spending levels.

434. ATCO Electric opposed the RPG's recommendation on the basis that it had provided an assessment of the validity of alternatives, particularly the run-to-fail alternative proposed by the RPG, for every category within this project.[205] It added that managing the activities that it has reviewed and assessed as being necessary within the test period, with a 50 per cent reduction in expenditures, would introduce serious risks to the safety of ATCO Electric personnel and the public; invite environmental incidents; introduce reliability concerns; introduce unplanned outage events beyond the capability of existing forecast staff levels to address; increase costs over time; and would be inconsistent with good utility practice.

Commission findings

435. ATCO Electric provided information in response to information request UCA-AE-040[206] regarding the basis for its forecast, including the exploration of alternatives. The Commission can verify from the application[207] that the 2010 actual expenditures for these two projects combined was $9.6 million however, there is no information available on the record to determine

[204] Exhibit 2, business cases, 50010/50020, page 3 of 10.
[205] Exhibit 51.01, response to information request UCA-AE-040.
[206] Exhibit 51.01.
[207] Schedule 10-4 of the application.

the actual expenditures for 2009. Consequently, the Commission cannot confirm the RPG's submission that the average annual expenditures in 2009 and 2010 were $9.0 million. Regardless, the actual expenditures in 2011 were $13.2 million and the forecast for 2012 is $17.7 million. The annual average for 2010, 2011 and 2012 is $13.5 million and the annual average for 2011 and 2012 is $15.5 million, with a forecast for 2013 of $14.9 million and a forecast for 2014 of $15.1 million. The forecasts for 2013 and 2014 are reasonably comparable to the annual averages of $13.5 million and $15.5 million.

436. As shown in Table 23, a significant amount of the forecast expenditures in the lines category are a result of external requirements, which are difficult to predict because they are not entirely under the control of ATCO Electric. The Commission considers that the expenditure levels in this category could fluctuate from year to year as the priorities of external parties change. Consequently, a simple comparison to historical expenditure levels is not a sufficient basis upon which to reduce the forecast for the test period. Accordingly, the Commission rejects the requested reductions to capital expenditures and capital additions made by the RPG.

Project 50041: System right-of-way widening

437. This program is intended to widen existing rights-of-way on older 240-kV and 144-kV transmission lines in order to maintain or re-establish tree-free clearance zones with line conductors. Tree-free zones, established at the time of construction of these lines, gradually erode over time due to the continuing growth and maturing of the vegetation and timber adjacent to these rights-of-way.

438. The existence of these mature timber stands can increase the potential for creating a fall-in tree contact with energized line conductors. Over time, these stands of timber grow to a point where, during the right conditions or weather event, trees from within these stands can come in contact with energized line conductors. Generally, a tree contact will cause a line outage and may compromise the integrated system. There is also the risk of forest fires.

439. ATCO Electric is obligated to complete regular hazard tree removal programs as outlined in *The Agreement for the Reduction and Prevention of Wildfires*, signed with the government of Alberta. The Alberta Reliability Standards also require stringent attention to the identification and elimination of potentially hazardous vegetation along with the annual inspection of 240-kV rights-of-way, and the reporting of related vegetation conditions. ATCO Electric specifically referred to Alberta Reliability Standard FAC-003-AB-1, stated that this project will support compliance with that standard, and argued that this project is required on older lines that were originally constructed to a 10-year tree-free standard.

440. ATCO Electric proposed this project as an ongoing annual program to be conducted over the next 10 to 15 years. The project work would be completed on older 144-kV and 240-kV transmission rights-of-way based on priority and evaluation of risk, best cost option, and approved scope of work. The forecast capital expenditures and additions are $7.0 million in 2013 and $5.7 million in 2014, based on a forecast of $15,000 per hectare. The project proposes to widen 465 hectares around transmission line 9L57 in 2013, and 380 hectares around transmission line 9L56 in 2014.

441. The RPG opposed approval of this project and referred to the business case for Project 50040, in which ATCO Electric stated that it has always identified and managed hazard trees in timber stands adjacent to transmission right-of-ways. Given this assertion from ATCO

Electric and the fact that the project is scheduled for a 10 to 15 year period, the RPG requested that the project be delayed by at least two years, a period in which the RPG considered system reliability would not likely be materially impacted. It further submitted that on a go forward basis the project should be presented in a business case which includes both a cost/benefit analysis as well as a minimum five-year annual expenditure forecast adjusted up or down to help normalize workload levels across all projects.

442. ATCO Electric indicated that rather than apply this program more broadly, it has identified two lines of significant concern for the test period, whereas the remainder of the system will continue to be managed through its regular program, which includes specific identification and removal of hazard trees. It argued that it must widen these rights-of-way in order to appropriately manage these matters, as opposed to addressing specific hazard trees on an ad hoc basis. It submitted that this project is not duplicative of its other vegetation management programs and is designed to address a specific hazard that is being introduced to the transmission system based on the age of existing facilities and associated vegetation growth. Continuing with the hazard tree removal programs only is no longer effective, as the majority of the adjacent forest stands now have the potential to strike the transmission lines.

Commission findings

443. None of the parties argued that this project should not be completed. The RPG only requested that it be delayed by two years. This is a new program and ATCO Electric has identified two specific lines for which the right-of-way is forecast to be widened in 2013 and 2014. It provided more information in response to information request UCA-AE-042,[208] including the fact that these two lines were constructed in 1976 to the 10-year tree-free standard. Considering the relatively small magnitude of the forecasted expenditures in the test period, compared to the overall forecast, and the statement from ATCO Electric that this project will support compliance with Alberta Reliability Standard FAC-003-AB-1, there is no justification to delay the expenditures for this project beyond 2013 and 2014. The RPG's statement that system reliability will not likely be materially impacted by a delay of this project is not substantiated. Its recommendation to delay the project by two years is consequently rejected.

444. Notwithstanding, based on the information provided for this project on the record of this proceeding, the Commission is not prepared to approve this entire project which, according to ATCO Electric, is an annual program for the next 10 to 15 years. The Commission has only approved the forecast expenditures and additions for the years 2013 and 2014 for the two lines identified as requiring immediate attention. In the event that ATCO Electric intends to continue with this project as indicated for the next 10 to 15 years, ATCO Electric is directed to bring forward a substantive business case and request approval in its next GTA for the forecast expenditures and additions for this project.

Project 50060: Substation rebuilds

445. ATCO Electric has indicated that it has a number of aging substations with significant civil and structural problems. Major structural components of substations, including control buildings, poles, insulators, foundations and ground grids age over time and eventually require rebuilding and replacement. When several of these components reach the end of life condition, a substation rebuild is undertaken in order to restore and preserve the functions of the substation

[208] Exhibit 51.01.

facility. In addition, as load increases and the transmission network expands, existing equipment may not have the appropriate specifications to meet system requirement. For example, existing breakers may lack sufficient capability to interrupt the fault currents in the aftermath of major system development, or older ground grids may not have sufficient capacity to manage increased fault levels.

446. Field inspection and review is undertaken of all substations on a bi-annual basis and candidate substations for a major life extension are identified. Many of the substation rebuild projects for 2013 and 2014 are coordinated with direct assigned capital projects at the same sites.

447. In response to information request CCA-AE-033(c),[209] ATCO Electric included details of the forecast amounts included in this project for 2013 and 2014. These forecast amounts are as follows:

Table 24. Capital maintenance – Project 50060: substation rebuilds

	2013 forecast		2014 forecast	
Description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
709S Vegreville	2.4	0.0	3.3	6.0
787S High Prairie	3.1	3.7	0.0	0.0
757S Battle River	1.1	10.7	0.1	0.3
847S Muskeg River	1.0	0.0	3.9	4.7
727S Kinuso	0.0	0.0	0.6	0.0
735S Swan River	1.9	2.5	0.0	0.0
720S Wabasca	1.2	1.9	0.0	0.0
789S Keg River	1.0	0.0	6.8	9.0
836S Steep Bank	1.0	0.0	1.5	2.5
717S Ethel Lake	0.0	0.0	0.5	0.0
797S Kemp River	1.4	1.9	0.0	0.0
Total	14.1	20.7	16.7	22.5

448. The business case submitted included a general project overview and summary, as well as a detailed business case for 787S High Prairie. In response to information request IPCAA-AE-033,[210] more information was provided with respect to the failure rate of the oil reclosers in ATCO Electric's substations. The business cases for the remaining substation rebuilds listed in Table 24 above, with the exception of Swan River, were submitted in response to information request IPCAA-AE-032.

449. In response to information request CCA-AE-033(d), ATCO Electric provided variance explanations for the differences between the actual/updated forecast capital additions (actuals for 2010 and 2011, updated forecast for 2012) and the approved forecast capital additions for these years. In response to information requests CCA-AE-033(f) and UCA-AE-043(b),[211] ATCO Electric provided details of the method it used to identify and prioritize candidates for

[209] Exhibit 53.01.
[210] Exhibit 54.02.
[211] Exhibit 51.01.

substation rebuilds, and an analysis that demonstrated how the chosen substations satisfy the criterion.

450. The RPG recommended that the substation rebuilds for 847S Muskeg River and 727S Kinuso be rejected completely, that 787S High Prairie be delayed by one year to 2014, and that the following projects be delayed for two years:

- 709S Vegreville
- 720S Wabasca
- 789S Keg River
- 717S Ethel lake
- 797S Kemp River

451. The revised forecast as recommended by the RPG is as follows:

Table 25. Capital maintenance – Project 50060: substation rebuilds, as recommended by the RPG

	2013 forecast		2014 forecast	
Description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
787S High Prairie	0.0	0.0	3.1	3.7
757S Battle River	1.1	10.7	0.1	0.3
735S Swan River	1.9	2.5	0.0	0.0
836S Steep Bank	1.0	0.0	1.5	2.5
Total	4.0	13.2	4.7	6.5

452. The RPG stated that the adjustments it recommended are based on a combination of deliberate deferrals, probable delays due to schedules in jeopardy, and weaknesses in the business cases. The RPG argued that a two-year delay would not materially increase the risk of failure faced today or over the test years, and that ATCO Electric has acknowledged that some of the substation rebuilds[212] have schedules which are in doubt due to regulatory or other delays.

453. Based on the AESO's plans for a 144-kV line from Otauwau to Slave Lake and conversion of the Slave Lake substation to 144-kV; as well as the High Prairie to Triangle 144-kV line upgrade project, the RPG raised concerns about the long term future of the remaining 72-kV line in the Kinuso area, and the substation, which only has load of 3.2 megavolt-ampere (MVA). It submitted that the 727S Kinuso rebuild should not be approved until ATCO Electric has fully explored the possibility of salvaging the substation and has established a 20-year plan for the remaining 72-kV line in the area.

454. The RPG further stated that the Muskeg River 847S substation connects the Muskeg River cogeneration plant, which is 70 per cent owned by ATCO Electric's affiliate, ATCO Power. It added that the complete replacement of the equipment at this substation raises a number of serious questions regarding the potential for a conflict of interest, including the role that ATCO Power had in the selection of the original nonstandard equipment which ATCO

[212] Those being 709S Vegreville, 787S High Prairie and 789S Keg River.

Electric now proposes to replace only 12 years after the substation was constructed. It submitted that the historical practice for dealing with obsolete relays should be used in this case, which is to replace one line of the equipment in order to create an available spare for each component, and then continue to do so as items fail, which is the same approach ATCO Electric has used for its network multiplexer upgrade replacement capital program. The RPG recommended that an independent review, by an uninvolved party, of the increased risk, if any, should be required before consideration is given to an immediate full replacement of the equipment at this substation.

455. When questioned on the need for the rebuilds within the test period in light of other system projects and growth, ATCO Electric indicated that the forecast expenditures are supported by business cases and that it reviews and implements these projects in conjunction with an assessment of other alternatives and system developments structures, and it seeks mitigation of the lines which still carry a risk identified as "moderate" within the test period.

456. ATCO Electric replied that the information it provided confirms that a comprehensive threshold risk/cost ratio is determined for each project and this ratio must be greater than or equal to eight in order for the benefits of proceeding with the project to outweigh the costs, which is the case for all the projects included in the forecast. It indicated that several of the rebuild projects are advanced, with design activities well underway, and because several are timed to coordinate with direct assigned capital projects, there are consequential impacts to delaying these rebuilds.

457. ATCO Electric stated that nowhere in the AESO's long-term plan does it contemplate the conversion of 727S Kinuso to 144-kV. The 72-kV system is adequate to meet the current loading requirements in the area of 3.2 MVA, and no other reasonable method of serving this load exists, since the next closest substation is 43 km away, in Slave Lake, which is not being converted to 144-kV. ATCO Electric submitted that the RPG's suggestion that line 6L91 (from High Prairie to Kinuso) be converted to a 25-kV distribution line was not supported by any technical or economic analysis which would demonstrate its feasibility.

458. ATCO Electric stated that the RPG has referenced information on ATCO Electric's website with respect to the 847S Muskeg River substation, and such information was not entered on the record during the proceeding, and was not put to its witnesses for comment or clarification. As such, ATCO Electric provided further details in its reply argument submission. The substation not only serves the Muskeg River cogeneration plant, but also oil sands developments in the area, those being the Albian Sands initial development and the Jackpine mine expansion. It would be highly inappropriate to apply a different standard of reliability to 847S Muskeg River than for its other facilities. In the case of the network multiplexer upgrade replacement program, ATCO Electric is able to salvage spare parts from other similar, decommissioned equipment, whereas in the case of 847S Muskeg River, similar equipment does not exist anywhere in its system.

459. ATCO Electric argued that an independent review requested by the RPG is unwarranted, and in any event, would simply confirm that a failure of 847S Muskeg River, after manufacturer support is removed completely, will lead to a situation where ATCO Electric is not able to restore service after a failure.

Commission findings

460. The Commission has examined this project in its entirety, rather than addressing each individual component and corresponding recommended adjustment made by the RPG. The decisions to rebuild and when to rebuild substations are based on judgement. Needless to say, the cost associated with a rebuild versus the risk associated with system reliability if a rebuild is not performed also involves professional judgement. In addition, once the decision is made to rebuild a substation, there is a forecast risk related to whether the rebuild will occur on schedule as planned, or not. ATCO Electric stated in response to information request CCA-AE-033(d) that "Substation rebuild projects are large and complex and are subject to schedule influences …" This is evidenced by the comparison of forecast to actual capital additions for this project for the years 2010, 2011 and 2012 that ATCO Electric provided in response to information request AUC-CCA-033(d). For the years 2010 to 2012, the total approved forecast additions were $19.0 million, while the actual/updated forecast additions for the same period were $11.3 million.

461. Once a decision is made to rebuild a particular substation, its rebuild also has to compete for resources with other substations forecast to be rebuilt. If resources are limited, a prioritization of individual substation rebuilds must occur, and if the amount of work forecast is more than the resources available to complete the work, some rebuilds are simply not completed. ATCO Electric included an assessment of the probability of completing each of the individual substation rebuilds forecast in 2013 and 2014. While the probability that a number of the rebuilds would be completed was determined to be high, many were rated as medium.

462. Given the strain on the labour resources available to complete all of the forecast capital project work during the test period, as acknowledged by ATCO Electric throughout the proceeding,[213] the difficulty in forecasting the completion timelines of these projects, and ATCO Electric's own assessment that there is only a medium likelihood that certain rebuilds will be completed during the test period, the Commission finds that a 25 per cent reduction to each of the forecast 2013 expenditures, 2013 additions, 2014 expenditures and 2014 additions is warranted and reasonably reflects the expected activity able to be completed during the test period. The Commission directs ATCO Electric to reflect these reductions in the compliance filing. This reduction is not to be applied to the Steep Bank substation rebuild, because the cost of this project is fully offset by a forecast customer contribution.

Project 50940: Mitigate double circuit contacts

463. The vertical clearance between the top and bottom circuit on the same structure was based on a design rule that was in place prior to 1999. This design rule was superseded in 1999 by the Alberta Electrical and Communication Utility Code, which required increased minimum spacing between the cross-arm of the transmission line and the cross-arm of the distribution line. If the loading of the line exceeds the safe clearance between the top and the bottom conductors, the line is mitigated.

[213] ATCO Electric indicated in paragraph 217 of the application (Section 10, page 10-12), that the AESO's 2012 long-term transmission plan forecasts that sustained oil prices will increase the demand for skilled labour in Alberta, resulting in labour shortages. ATCO Electric anticipated cost escalations of 25 per cent relating to the construction of transmission facilities, starting in 2013. ATCO Electric indicated during the oral hearing that it had talked to the AESO about constraints on construction resources and the amount of work going on in the market (Transcript, Volume 6, page 1226, lines 1-19).

464. This project is a continuation of the multi-year program included and approved in previous GTAs to mitigate the potential for contacts (outages) between two circuits on the same structure. The project work entails identifying potential high risk structures from design and operating information, field verification/data gathering, engineering review of risks and non-compliances, and engineering and upgrading of facilities where required.

465. The line audits/survey data capture started in 2005 and has been followed by detailed engineering and construction. The engineering and construction work will continue into future years, while data capture and the majority of the engineering analysis will be completed by the end of 2014. In total, 1,465 km of line will have been surveyed. A corresponding distribution project will be allocated a portion of the remediation costs.

466. Without remediation, future double circuit conflict probability is very high and will likely increase due to continued load and generation growth. ATCO Electric provided details about double circuit contact events that occurred on October 3, 2003, March 9, 2004, March 11, 2004, and May 14, 2004.

467. ATCO Electric is planning line remediation on seven lines in 2013 and on five lines in 2014. With the exception of six structures on one high priority line that are to be mitigated in 2013, it is proposing to begin mitigation of those lines which carry a risk identified as moderate. ATCO Electric added that new lines can emerge that are also high priority.

468. More information about this project, including the mitigation strategy and details of the forecast amounts for each line, was provided in response to information request CCA-AE-033(i) and (j).[214] Additional information, including how the costs of this project are allocated between transmission and distribution, was submitted in response to information requests IPCAA-AE-035, IPCAA-AE-036, and IPCAA-AE-037.[215]

469. The RPG recommended that this entire project be rejected for the test period. It indicated that there have only been four outage events reported by ATCO Electric, one in 2003 and three in 2004, that ATCO Electric confirmed that no further outages have occurred over the last ten years, and ATCO Electric has no knowledge of any significant occurrences prior to 2003. The RPG also stated that the high priority lines have been addressed, the program is now for medium priority lines, and that there is weak justification presented in the business case.

470. ATCO Electric replied that it is actively monitoring loading on lines that are not mitigated to the full thermal rating to ensure that double circuit clearance issues do not cause outages. It stated that a lack of outages is not an indication that conflicts do not exist, but rather is an indication that the monitoring processes it has in place are working. The lines for which mitigation is proposed for the test period were built over a number of years under different code requirements, but have spans that are rated zero MVA when the current code is applied. When determining which spans in a line should be mitigated, ATCO Electric evaluates the risk to public safety, the expected line loading under a variety of conditions, the number and complexity of spans requiring mitigation to achieve particular line ratings, and the cost of mitigation.

[214] Exhibit 53.01.
[215] Exhibit 54.02.

Commission findings

471. As mentioned in the response to information request UCA-AE-048(b),[216] business cases for this project were also submitted as part of the 2005-2006 GTA and the 2007-2008 GTA, and forecast costs for this project have been approved since that time. With the exception of six structures on one line that has been identified as a high priority, ATCO Electric is now forecasting to work on lines that are identified as having only a moderate risk. Considering that there have been no outages since 2004 due to double circuit contacts, the Commission considers there to be reasonable doubt that there will be risks to the reliability of the system if this program does not proceed as forecast over the test period. Accordingly, the Commission finds that the line survey, which is forecast to be completed during the test period, nine years after the program started, should be completed, and that the remediation of the six structures on the one high priority line identified by ATCO Electric should be completed. The forecast costs to complete these tasks are approved, and the Commission directs ATCO Electric, in the compliance filing, to only include costs that are required to complete the line survey and to remediate the six structures on the one high priority line.

472. With regard to continuation of this project, once ATCO Electric completes the line survey in 2014, it is directed to submit detailed business cases in a future GTA, describing the results of the survey, and evaluating the alternative costs of remediation for any future lines. This evaluation should be done on a line by line basis, and include the results of any prioritization assessment with respect to any lines for which remediation is recommended. The business case should detail possible alternatives which were highlighted in the original business case filed in the 2005/2006 GTA Project 50940, where on page 7 ATCO Electric said:

> Field measurements are also important in the selection of the best remedial action strategy on a section by section basis. For example, a line with a relatively small number of spans with potential problems may be mitigated differently than a line where the majority of spans have a potential clearance issue.

473. And also on page 8:

> The field data collection will also confirm that the older line poles have not settled into the ground due to wet soil conditions in some areas and that the older construction methods meet the design intent i.e. the earlier methods of tensioning conductors was not as accurate as the current methods. Field measurements are also important in the selection of the best remedial action strategy on a section by section basis. For example, a line with a relatively small number of spans with potential problems may be mitigated differently than a line where the majority of spans have a potential clearance issue.

474. These options for mitigation examples, which should be included in the business case, are also highlighted in Appendix A of the Project 50940 business case in the 2007/2008 GTA.

475. The CCA recommended that a five per cent reduction be made to forecast capital additions in each of 2013 and 2014 for the entire capital maintenance – general area, to reflect ATCO Electric's poor forecasting accuracy in this area. This results in reductions to capital additions of $4.3 million in 2013 and $3.7 million in 2014. The reductions the Commission has directed in this capital maintenance – general area exceed the levels recommended by the CCA and therefore the Commission considers that the CCA's recommendation has been addressed.

[216] Exhibit 51.01.

11.8.2.3 Capital maintenance – telecommunication

476. ATCO Electric's telecommunications network is integral to the safe, reliable and efficient operation of the transmission system. The telecommunications system carries traffic to facilitate SCADA operations, protection, mobile radio and data communications. The safe and reliable ongoing operation of the transmission system as well as the efficient restoration of the transmission system following a disturbance relies heavily on the reliable operations of all these functions. The forecast is as follows:

Table 26. Capital maintenance – telecommunication: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
50400: Capital maintenance - telecommunication	$1.4	$1.3	$2.0	$1.4
59911: Telecom site power backup	9.4	13.5	8.3	8.3
59943: Grande Prairie area telecom reliability	1.8	0.0	1.9	3.8
59946: Mobile communication system	0.6	0.0	0.3	3.7
59948: Microwave capacity upgrade	1.8	0.0	1.9	3.8
59955: Network multiplexer upgrade	3.6	3.6	5.4	5.4
Total	$18.6	$18.4	$19.8	$26.4

Source: Exhibit 188.02, Schedule 10-4.

477. Projects 59911, 59955, 59948 and 59943 are all existing previously approved projects for which ATCO Electric is seeking approval to continue. Project 59911 is intended to ensure that power to critical substations, and telecommunication and substation facilities, is available to support restoration efforts following a major disturbance. Project 59955 will address equipment obsolescence issues and improve the functionality of the telecommunications system. Project 59948 is proposed to ensure that the telecommunications system has sufficient capacity to meet growing needs and Project 59943 is proposed in order to provide sufficient capacity to meet growing needs, and to address equipment obsolescence issues.

478. ATCO Electric's mobile communication system, which is the subject of Project 59946, is intended to ensure reliable communications with field operations, particular in times of system disturbance or under emergency conditions. Project 59946 would upgrade ATCO Electric's mobile communication system from aged and obsolete technology to a new digital communication network capable of providing the reliability, coverage, ease of use, and data communications required by today's utility operations. The need to devise an appropriate cyber security protection strategy for the mobile radio program has extended this project through the 2013-2014 test period.

Discussion of issues

479. The CCA was critical of ATCO Electric's ability to accurately forecast this entire category, and recommended an overall reduction in capital additions of 50 per cent to the entire category in each year, based on the 50 per cent negative variance between approved and actual capital additions in the 2010 to 2012 period. The CCA submitted that timing of capital additions is a critical matter and if, actual additions lag forecasts by one or more years, the customers of

ATCO Electric are being asked to pay for services that are not required in a given test year. The CCA recommended specific reductions as follows:

Table 27. CCA recommended reductions for capital maintenance – telecommunication

	2013 additions	2014 additions
	($ million)	
Total	9.2	4.0

480. The UCA also raised a concern about ATCO Electric's ability to accurately forecast this area, and had additional concerns with the level of capital expenditures forecast over the test period. It recommended reductions to capital expenditures of $9.3 million in 2013 and $9.9 million in 2014. The UCA indicated that the forecast capital expenditures for 2013 and 2014 of $18.6 million and $19.8 million respectively, were not reasonable when compared to the average annual actual capital expenditures over the 2009 to 2011 period of $4.4 million, and the 2012 forecast amount of $9.9 million. It questioned why ATCO Electric would seek to increase its spending in this category when the level of spending on direct assigned capital projects is so large. It stated that in 2010, ATCO Electric spent 75 per cent less than it forecast in the GTA, and the corresponding figure for 2011 was an underspend of 26 per cent. The average actual annual underspend for the years 2008 to 2011 is approximately 38 per cent, while the average actual annual underspend for the years 2010 and 2011 averages 50 per cent, which is the UCA's recommended reduction for each year.

481. The UCA added that the forecast capital expenditures of $9.4 million in 2013 and $8.3 million in 2014 for Project 59911, are well in excess of the actuals of $0.6 million in each of 2008 and 2009, $0.1 million in 2010 and $0.8 million in 2011. It submitted that the under-spending for this project was 94 per cent in 2010 and 79 per cent in 2011.

482. ATCO Electric stated that the growth on the system related to the direct assigned capital projects work is increasing the need for reliable and increased telecommunication network capacity. It added that many of the telecommunications projects are interrelated and deferring one project could hamper the completion of other projects. It submitted that in recent years projects were impacted by a lack of clarity on what level of consultation and regulatory review various projects required, but this situation has now been resolved. ATCO Electric provided a status update with respect to projects 59943, 59946, 59948, 59911 and 59955.

483. The UCA submitted that while the qualitative updates for these five projects include ATCO Electric's assertion that there is low schedule risk, the updates do not adequately explain why ATCO Electric is now capable of executing telecommunication projects over the next two years that are twice the size of its most recent plans. The information does not demonstrate ATCO Electric's ability to expand its telecommunication spending within the test period.

484. In response to the criticisms regarding its ability to accurately forecast this expense, ATCO Electric stated that for its entire non-direct assigned capital projects additions, the overall variance between actual and applied-for amounts has been approximately two per cent over a full 10-year period. In its view, the focus of the UCA solely on telecommunications does not present a complete picture of ATCO Electric's ability to accurately forecast these capital projects.

485. The RPG submitted that the average annual capital expenditures in this area for the years 2006 to 2011 was $4.3 million, and that ATCO Electric's forecast capital expenditures for 2013

and 2014 are more than 4.5 times this amount. It submitted that given the predicted labour market shortages and resulting likelihood of paying a premium for all capital projects, the forecast capital expenditures should be reduced.

486. The RPG recommended specific reductions by project as follows:

Table 28. RPG recommended reductions for capital maintenance - telecommunication[217]

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
50400: Capital maintenance - telecommunication	1.4	1.4	1.3	1.0
59911: Telecom site power backup	4.5	2.2	8.3	8.3
59955: Network multiplexer upgrade	0.6	0.6	3.6	3.6
Total	6.5	4.2	13.2	12.9

Project 50400: Capital maintenance – telecommunication

487. ATCO Electric operates its own dedicated telecommunication system, and it has an obligation to maintain the safety and integrity of its facilities. As assets age, wear out, or no longer meet requirements, the most effective way of maintaining intended functionality, safety and performance is through the capital maintenance project. A detailed plan for the current year is developed in the year prior to execution, and is determined by analyzing data collected from the various sources such as interviews and discussions with field, maintenance and engineering staff, reviewing age of equipment, and examining test and condition results. This is a shared project with distribution.

488. ATCO Electric provided the following forecast amounts by the drivers for these costs:

Table 29. Capital maintenance – telecommunication, expenditures by category for Project 50400[218]

Description	2013 forecast	2014 forecast
	($ million)	
System performance	0.3	1.1
Life extensions	0.3	0.1
Replacements	0.8	0.8
Total	1.4	2.0

489. ATCO Electric indicated that it conducts a detailed analysis of individual projects and programs to ensure that the business drivers, associated risks and alternatives are adequately considered, and it provided an example of an individual project analysis. More information on this specific project was provided in response to the following information requests: AUC-AE-033, AUC-AE-034, UCA-AE-038(a) and (d), and UCA-AE-050.

[217] Exhibit 238.02, RPG argument, page 6.
[218] Exhibit 2, business cases, 50400/70400, page 2 of 10. Transmission's share is 50 per cent of the total figures included in the business case.

490. The RPG submitted that based on historical expenditure levels, especially the levels for 2010 and 2011, which averaged $1.1 million per year, this project should be reduced by 35 per cent to remain consistent with past spending.

Project 59911: Telecommunication site power backup

491. ATCO Electric asserted that this project is required to ensure the availability of key telecommunications facilities during extended system power outages. The telecommunication facilities provide system visibility, teleprotection and mobile radio functions which are critical to enabling a safe, coordinated and timely restoration of the electrical grid. The telecommunication system provides mobile radio communications and SCADA for this system visibility and control, in addition to other services.

492. The mobile radio system is a critical component of system operations. It provides a highly reliable means of coordinating field work such as switching orders. It is an important safety tool for field workers, particularly for those who need to work alone, and no other means of communication can provide the same consistent level of availability. SCADA visibility and control is essential for operating and restarting the electrical system. Without SCADA, visibility and control of the electrical system would be lost because ATCO Electric does not have the necessary field staff to man substations to provide the necessary control and visibility.

493. Substations require battery power and heat to operate, and a number of key substations are part of the provincial black start plan. Black starting the electrical system is estimated to take 48 hours or more. A substation has sufficient battery power backup for an eight hour duration at -40 Celsius. Without generator set back-up power, ATCO Electric runs the risk of losing visibility and control of the critical facilities, which would result in a prolonged outage up to and beyond the 48-hour black start duration. Based on this, a planning report was initiated to identify the most appropriate method of providing the additional 40 hours of back-up power.

494. This project will result in the installation of 18 kilowatt (kW) stationary propane powered generators at 44 of ATCO Electric's 116 stand-alone microwave and mobile radio sites. These generators will have sufficient propane to operate for at least 48 hours. If the grid power is not restored after 48 hours, the batteries will provide power for a further eight hours of operation. This project is scheduled to be completed in 2013 and is a cost-shared project between distribution and transmission, with transmission's share of the total costs being 80 per cent.

495. A subsequent project, scheduled for 2014, will result in the installation of generators at 51 of ATCO Electric's transmission substation sites. Thirty of these substations contain key telecommunication facilities, and the telecommunication load at these sites is included in the power requirements of the generator sets. These propane powered generator sets range in size from 50 kW to 200 kW based on the load requirements at the substation. These generators will have sufficient propane to operate for at least 48 hours. It is estimated that 14 back-up generators will be installed in 2014, with the remaining 37 being installed in 2015 to 2016. At sites having co-located telecommunications equipment, the cost split to distribution will be based on 20 per cent of the cost of an 18 kW generator. All remaining costs will be charged to transmission.

496. ATCO Electric referred to the response to information request UCA-AE-049(a),[219] in which it described that the need for this project was highlighted as a result of the Slave Lake area fires in 2011. It submitted that this recent example illustrates the importance of installing emergency back-up generators at its telecommunication sites, in order to ensure that ATCO Electric is able to effectively respond to unexpected events and outages that could ultimately affect electrical service to the entire province.

497. The RPG submitted that there is no urgency to complete this program and added that the probability that it will ever be needed is very low. It indicated that if this project did not proceed, the consequences associated with a system outage would be the risk of a slower restoration of the system than what could be achieved with the new functionality ATCO Electric is adding to its communications system. The RPG submitted that this program can be delayed for at least two years, in order to reduce workload in the 2013 and 2014 period without any material risk to customers. Cost savings could also likely be achieved if the program were phased in gradually, with the addition of the new generators on an opportunity basis when other work is planned for each specific site.

Project 59955: Network multiplexer upgrade

498. ATCO Electric submitted that this project is required to replace the existing multiplexer platform due to obsolescence, and to facilitate an upgrade to multi-protocol labeled switching technology, which will provide enhanced system performance. ATCO Electric currently utilizes multiplexers at telecommunications sites for access to services such as teleprotection, SCADA, voice, mobile communications and secure internet protocol. The vendor for these multiplexers has provided notice that it no longer manufactures this device, and that it will no longer provide support for the product or the network management system beyond 2013. The existing multiplexers at 112 sites will be replaced with multi-protocol labelled switching technology. The project began in 2010 and is forecast to be completed in 2018. This multi-year transition will ensure technologists are well trained on the new technology, prior to full decommissioning of the old system. Salvaging the old system for use as spares will also allow for extending the overall lifespan of the old system, reducing the risk of operating without vendor support. This is a cost-shared project with transmission being allocated 80 per cent of the costs.

499. The RPG stated that, given ATCO Electric's view of a labour market shortage and that fewer vendors will have sufficient resources and capacity to submit compliant bids, the rate of conversions should remain at or below the 2011 level of expenditures of $1.8 million. Cost savings could also likely be achieved with the work carried out on an opportunity basis, when other work is planned for each specific site.

Commission findings

500. The Commission has considered ATCO Electric's submission that, in recent years, projects were impacted by a lack of clarity on the level of consultation and regulatory review required for various projects, and that this situation has now been resolved. However, ATCO Electric did not demonstrate how the differences between the actual amounts spent and the forecast amounts in each year from 2008 to 2011 were due to a lack of clarity on the level of consultation and regulatory review. In addition, the Commission finds that ATCO Electric's forecasting accuracy for this category of projects is poor, and the Commission does not accept

[219] Exhibit 51.01.

the position of ATCO Electric that its specific forecasting accuracy for telecommunications should be ignored in favour of a consideration of ATCO Electric's overall forecasting accuracy for non-direct assigned capital projects. Each category of capital maintenance should be capable of being forecast over a two-year test period with a reasonable level of accuracy, particularly where the utility takes the risk of the forecast.

501. Given its poor history of forecasting in this area, the Commission is not persuaded by ATCO Electric that it will be able to complete the work it has forecast during the test period, particularly during a period of unprecedented capital spending. Based on the average actual under-spending in this area from the years 2008 to 2011, a period which did not include the level of capital activity that is forecast to be conducted over this test period, the Commission finds a reduction of 40 per cent in each forecast test year to be reasonable. The Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures and additions in each of 2013 and 2014, for telecommunication capital maintenance, by 40 per cent.

11.8.2.4 Capital maintenance – SCADA/EMS

502. ATCO Electric's SCADA/EMS projects provide support to the system control functions and ensure the security of its operational network. Project 59919, a shared project with distribution, is intended to protect critical cyber assets against attacks, and to comply with the latest revisions of applicable Alberta Reliability and North American Electric Reliability Corporation (NERC) standards. ATCO Electric provided more information on these projects in response to information requests AUC-AE-040,[220] UCA-AE-053[221] and CCA-AE-036.[222]

503. The latest forecast for this area is as follows:

Table 30. Capital maintenance – SCADA/EMS: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
50900: Operational information systems	0.4	0.4	0.9	0.9
59919: Operation cyber security	1.8	1.8	2.0	2.0
Total	2.2	2.2	2.9	2.9

Source: Exhibit 188.02, Schedule 10-4.

Discussion of issues

504. The RPG submitted that the average annual capital expenditures in this area for the years 2006 to 2011 was $1.2 million, and that ATCO Electric's forecast capital expenditures for 2013 and 2014 are more than double this amount. It added that these projects are a continuation of those previously approved, and 2013 and 2014 are the last two years of a five-year program. Based on the historical expenditure levels, and more specifically the 2010 and 2011 expenditure levels, which averaged $1.3 million per year, the forecast expenditures for this area should be reduced by 50 per cent in each year.

[220] Exhibit 50.01.
[221] Exhibit 51.01.
[222] Exhibit 53.01.

Commission findings

505. The RPG's recommendation was based on keeping the forecast expenditures at the actual annual level achieved for the years 2006 to 2011. The latest forecast expenditures for 2012 of $1.7 million, provided by ATCO Electric, reflect an increase over the trend in 2006 to 2011. The RPG did not submit that either of the two programs listed in Table 30 above were not necessary, nor did it raise any concerns with ATCO Electric's forecasting accuracy. The Commission finds that ATCO Electric has justified the need for the continuation of, and the expenditure levels associated with, Project 59919 for cyber security, in order to comply with the latest revisions of applicable Alberta Reliability and NERC standards. The RPG's request is therefore denied.

11.8.3 Direct assigned projects

506. As set out in Section 11.1.3 of this decision, direct assigned capital projects are subject to a separate proceeding in order to assess the project need, with the AESO submitting a needs identification document (NID) to the AUC for approval. ATCO Electric stated that business cases were provided for direct assigned capital projects over $500,000 within the test period. These business cases provide information about the status of the project, including the AESO's NID submission to the Commission. The most significant capital expenditures and additions in the test period are associated with major transmission system development identified by the AESO. The most significant of these projects, the EATL project, is designated critical transmission infrastructure by the government of Alberta, and therefore no NID application was required for this project.

507. The latest forecast of direct assigned capital projects by subcategory[223] is as follows:

Table 31. Transmission direct assigned capital projects forecast

	2013 forecast		2014 forecast	
Subcategory	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
58001: EATL	653.7	0.0	575.3	1,567.5
HRTD	213.2	650.7	23.0	30.1
NETD	51.2	150.7	0.0	0.0
North Central Transmission Development (NCTD)	39.9	36.8	32.9	64.7
Central East Transmission Development (CETD)	162.7	251.2	90.1	38.0
Pipeline program	132.9	169.1	44.6	67.6
North central region	48.2	54.9	22.9	46.0
North east region	81.1	34.5	274.7	205.8
Central east region	24.5	14.0	18.8	8.4
Total	1,407.4	1,361.9	1,082.3	2,028.1

Source: Exhibit 188.02, Schedule 10-4.

508. ATCO Electric provided a further update with respect to its direct assigned capital projects forecast for the CETD, north central region, and north east region sub-categories, but did

[223] With the exception of the EATL project, which does not have a subcategory.

so after the omissions and updates filing was submitted.[224] It stated that it would make all revisions necessary to reflect this update in the compliance filing.

509. The RPG recommended a number of reductions to the forecast direct assigned capital projects identified in this proceeding. The Commission has included the summary total of the RPG's recommended reductions in the following table:

[224] This update is included in Exhibit 135.01.

Table 32. RPG recommended forecast for the direct assigned capital projects[225]

	2012		2013				2014		
	Exp.	Adds	CWIP open	Exp.	Adds	CWIP close	Exp.	Adds	CWIP close
	($ million)								
ATCO Electric forecast[226]			1,124.5	1,407.4	1,361.9	1,170.0	1,082.3	2,028.1	224.2
Adjustments in compliance filing[227]			0.0	(63.1)	(63.8)	0.7	58.8	58.9	0.6
ATCO Electric revised forecast			1,124.5	1,344.3	1,298.1	1,170.7	1,141.1	2,087.0	224.8
RPG recommended adjustments									
EATL[228]			(52.1)	(390.9)	0.0	(443.0)	(15.2)	(1,567.5)	1,109.3
HRTD[229]			(92.5)	(54.8)	(147.3)	0.0	(7.3)	(7.3)	0.0
NETD	(133.1)	(133.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCTD[230]			0.0	(23.0)	0.0	(23.0)	0.0	(23.0)	0.0
CETD[231]			0.0	(20.3)	(20.3)	0.0	(69.3)	(37.7)	(31.6)
Pipeline program[232]			(5.6)	(17.5)	(23.1)	0.0	0.0	0.0	0.0
North central region[233]			(0.6)	0.0	(0.6)	0.0	0.0	0.0	0.0
North east region[234]	0.0	0.0	(0.1)	(8.7)	0.0	(8.8)	(68.9)	(72.7)	(5.0)
Discrete adjustments	(133.1)	(133.1)	(150.9)	(515.2)	(191.3)	(474.8)	(160.7)	(1,708.2)	1,072.7
RPG aggregate adjustment[235]	0.0	0.0	0.0	(45.0)	(53.0)	8.0	(42.0)	(6.0)	(28.0)
Total RPG adjustments	(133.1)	(133.1)	(150.9)	(560.2)	(244.3)	(466.8)	(202.7)	(1,714.2)	1,044.7
Forecast recommended by the RPG			973.6	784.1	1,053.8	703.9	938.4	372.8	1,269.5

[225] Exhibit 238.02, RPG argument, Volume 2, page 83.
[226] Exhibit 188.02, Schedule 10-4.
[227] Exhibit 135.01.
[228] This consists of the information in Table 34, and $57.0 million for the use of Bechtel as the EPCM provider.
[229] This consists of the information in Figure 12 of the RPG argument, Volume 2, Exhibit 238.02, page 36; plus $35.0 million for the use of Bechtel as the EPCM provider.
[230] Exhibit 238.02, RPG argument, Volume 2, page 96, Figure 16.
[231] This consists of the information in Figures 20, 23 and 25 of the RPG argument, Volume 2, Exhibit 238.02, pages 54, 57 and 59.
[232] This consists of the information in Figure 28 of the RPG argument, Volume 2, Exhibit 238.02, page 62.
[233] This consists of the information in Figure 30 of the RPG argument, Volume 2, Exhibit 238.02, page 64.
[234] This consists of the information in Figures 33 and 35 of the RPG argument, Volume 2, Exhibit 238.02, pages 70 and 71.
[235] This consists of the information in Table 48 of this decision.

510. As noted previously in this decision, interveners raised a number of issues that are not specific to any particular direct assigned capital projects but instead are common to the entire category of direct assigned capital projects. These common issues were as follows:

- contingency amounts included in the forecast
- accuracy of forecasts
- planning process
- budget priority
- transmission line design and optimization
- cost and performance audits
- inter-affiliate code of conduct

511. In this decision, the Commission has generally addressed the planning process in sections 11.1 and 11.3, the budget priority in Section 11.3, and cost and performance audits recommendations in sections 11.5 and 11.9.4. Of the remaining issues, contingency amounts included in forecasts is addressed in Section 11.9.1, accuracy of forecasts is addressed in Section 11.9.2, transmission line design optimization is addressed in sections 11.4 and 11.9.3, and inter-affiliate code of conduct concerns is addressed in Section 11.9.5.

11.8.3.1 Eastern Alberta Transmission Line project

512. The EATL project is one of six facilities incorporated into four projects deemed to be critical transmission infrastructure by the Alberta government in the *Electric Statutes Amendment Act, 2009*. More specifically, the scope of the EATL project involves the construction of approximately 485 km of 500-kV direct current (DC) transmission line, two alternating current (AC)/DC converter stations, one in the Redwater-Gibbons area northeast of Edmonton and another in the Brooks area, and other associated facilities (i.e., 500-kV AC transmission lines, 240-kV transmission lines, optical repeater sites, fibre optic cables, etc.). The converter stations will be capable of operating as an inverter so that power can flow both ways. ATCO Electric has assembled a dedicated team to complete this project and is continuing its planning, procurement of material and securing construction services to meet the proposed ISD of December 31, 2014. More details are included in the project summary that was filed as part of the application.[236]

513. The forecast for this project is as follows:

Table 33. EATL project forecast

	2013 forecast		2014 forecast	
	Expenditures	Additions	Expenditures	Additions
	($ million)			
58001: EATL	653.7	0.0	575.3	1,567.5

Source: Exhibit 188.02, Schedule 10-4.

[236] This project summary is included in Exhibit 2, the business case for Project 58001.

514. Based on the response provided to undertaking response question RPG-AE-26,[237] the RPG recommended that the Commission reduce the 2012 closing CWIP balance to reflect the fact that expected milestone payments in 2012 were $52.1 million lower than forecast in ATCO Electric's omissions and updates filing.

515. The Commission has previously directed in this decision that ATCO Electric update the application as part of the compliance filing to incorporate the 2012 actual capital expenditures. Therefore the reduction recommended by the RPG will be reflected in the compliance filing and no additional direction is required. The Commission directs that a $52.1 million increase in capital expenditures for 2013 be included in the compliance filing as a result of the delay in milestone payments for 2012, and this amount not be included in the calculation of the nine per cent reduction with respect to forecasting accuracy as directed in paragraph 777 of this decision.

516. The RPG raised concerns regarding the use of third-party engineering, procurement and construction management (EPCM) services for this project and the HRTD program. This issue is addressed by the Commission in Section 11.8.3.10 of this decision.

517. The RPG also made specific recommendations regarding whether ATCO Electric could realistically meet the forecast ISD of December 31, 2014, whether the ISD should be intentionally delayed, and whether the forecast cost of the converter stations is reasonable.

Summary of recommended reductions

518. The RPG made the following recommendation with respect to the forecast capital expenditures and additions for the EATL project.

Table 34. RPG recommended forecast for the EATL project[238]

	2013				2014		
	CWIP Open	Exp.	Adds	CWIP Close	Exp.	Adds	CWIP Close
	($ million)						
ATCO Electric forecast	$338.6	$653.6	$0.0	$992.2	$575.3	$1,567.5	$0.0
RPG recommended adjustments							
Milestone payment	(52.1)	52.1	0.0	0.0	0.0	0.0	0.0
Converter station excess costs	0.0	(94.4)	0.0	(94.4)	0.0	0.0	(94.4)
Schedule delay	0.0	(348.6)	0.0	(348.6)	41.8	(1,567.5)	1,260.7
Total adjustments	(52.1)	(390.9)	0.0	(443.0)	41.8	(1,567.5)	1,166.3
RPG forecast	$286.5	$262.7	$0.0	$549.2	$617.1	$0.0	$1,166.3

[237] Exhibit 224.01.
[238] Exhibit 238.02, RPG argument, Volume 2, page 28.

In-service date

519. The RPG submitted that there is a substantial possibility that ATCO Electric will not meet the forecast ISD of December 2014, for the following reasons:

- The updated project milestone schedule provided during the oral hearing[239] showed that a number of work activities were substantially behind schedule.
- ATCO Electric is currently in the process of modifying the project execution plan to reflect the fact that 25 per cent of the route approved by the Commission consisted of alternate route segments.
- ATCO Electric made substantial commitments during the EATL project facility application that will impose considerable additional burdens, including evaluating the use of monopole towers.
- ATCO Electric is only now visiting landowners along the alternate route, and there is uncertainty regarding whether these landowners will agree to early access agreements in order for ATCO Electric to acquire easements, or whether ATCO Electric will need to apply to the Surface Rights Board.
- Other preparatory requirements include over 1,000 crossing agreements, relocation of a pipeline, outstanding Department of Fisheries permitting and approval and completion of an environmental protection plan.
- A comprehensive and up-to-date schedule that properly reflects the adjustments required as a result of the alternate route approval has not been filed.
- Land acquisition, foundation installation and line stringing activities are dependent on permitting and right-of-way access, which remain unfinished. A delay in this preparatory work suggests a delay in the other activities.

520. In addition to the delays that will arise due to the complex nature of the EATL project, the RPG questioned whether there should be a deliberate effort made to delay the ISD, especially if such a delay is beneficial to managing and even reducing the overall cost of transmission in the province. It submitted that the opportunity for delay exists based on the following reasons:

- The line is not required for reliability and a delay of the ISD will have no material consequences for either load customers or suppliers.
- The AESO is aware of the economic consequences of the EATL project's ISD and the RPG expects the AESO and ATCO Electric to hold further discussions on the economic impact of a change to the ISD.
- The latest schedule shows construction occurring in three segments of approximately 160 km, each being constructed at the same time. The labour demand is therefore roughly three times as great as it would otherwise be if the three segments were scheduled in sequence or at least reasonably staggered. Staggering the segments without overlapping labour demands will free up contractors and workers for other transmission lines in the province and reduce the pressure gripping the construction services market.

[239] Exhibit 161.01.

521. The RPG submitted that the evidence demonstrates that a delay of the ISD will not pose a risk to system reliability or to system congestion. Accordingly, if the present ISD is relaxed, ATCO Electric and its contractors should be in a better position to re-evaluate the schedule and to streamline the development in a manner that does not place spurious pressure on costs.

522. The RPG submitted that it is realistic to expect an eight-month delay in the EATL project's transmission line schedule, given the fact that the latest project update demonstrated that the project was behind schedule, and no schedule exists before the Commission at this time that properly reflects all of the conditions, requirements and impacts of the Commission's November 15, 2012, facility decision approving the EATL project. Consequently, the RPG recommended that the Commission reduce the capital expenditure forecast for the EATL project to reflect an eight-month delay in the development of the transmission line portion of the project. It also recommended that the ATCO Electric be directed to consult with the AESO to prioritize the EATL project expenditures, and select an appropriate schedule for capital expenditures that will assist in reducing the pressure on resources and costs during the test period, with the aim of reducing the overall cost of transmission in the province.

523. ATCO Electric referred to the detailed explanation of the EATL project schedule and achievability of milestones it provided in response to follow-up questions from the RPG,[240] and stated that based on the current status of this project and the work completed to date, it is confident that the forecast ISD will be met. It confirmed that it has already taken the six-month delay resulting from the Government Critical Transmission Infrastructure review into account by shifting the ISD from mid-2014 to the end-of-2014, and it added that the transmission line itself is forecast to be available by August 31, 2014.

524. ATCO Electric asserted that it is on track to complete the transmission line portion of the project by August 31, 2014; that the AESO has confirmed the December 2014 ISD; and that the Commission has provided a similar ISD in the permit and licences granted to ATCO Electric in the EATL project facilities application.

525. ATCO Electric submitted that the RPG's position that cost savings will occur if the transmission line is constructed in three consecutive segments is speculative. During the competitive bid process, contractors were given considerable flexibility on the contract form and pricing structure they wished to use. Bidders could submit separate pricing for each of the three segments of the line and indicate whether they were bidding on one, two or all three segments. The lowest bidder was offered a discount if it were awarded all three segments.

526. ATCO Electric indicated that it is on the verge of awarding the contract for the transmission line construction to the lowest bidder and that the staging of the work, the number of work phases, and the work crews have already been discussed and agreed upon with the contractor. It stated that any attempt to renegotiate the execution schedule for the construction work will very likely result in increased costs from the contractor, as well as additional ongoing overhead and indirect costs, while the project remains inactive

Commission findings

527. The Commission is not prepared to direct that the ISD for the EATL project be delayed, because approval for any delay in a direct assigned capital project is within the purview of the

[240] Exhibit 224.01, response to RPG-AE-031.

AESO. However, the Commission agrees with the RPG that it is doubtful that ATCO Electric will achieve its forecast ISD of December 31, 2014, given all of the factors identified by the RPG that can impact the project schedule. Accordingly, the Commission will make an adjustment to ATCO Electric's forecast revenue requirement to reflect this finding.

528. The RPG suggested that an eight-month delay would be realistic, and recommended reducing capital expenditures in 2013 by $348.6 million, and increasing expenditures in 2014 by $41.8 million, with a result that $306.8 million of capital expenditures would be incurred in 2015. The RPG produced no details of how it arrived at the eight-month delay forecast or the cost figures it recommended, and consequently the Commission cannot make any assessment as to the reasonableness of these figures.

529. ATCO Electric's latest forecast included capital expenditures of $653.7 million in 2013 and $575.3 million in 2014. The Commission considers that there is no reason to shift any 2013 planned expenditures into 2014, as work on the project should not be delayed in 2013, because there is more than enough work planned for 2013 to offset any schedule delays. In the Commission's view, it is reasonable to expect that a shift in expenditures would occur between the years 2014 and 2015, since that is when the schedule delays could impact the amount of work that is left to be completed. There is no breakdown by month for the $575.3 million in expenditures that are forecast for 2014, and Exhibit 135.01 shows that the expenditures will be completed by November 2014. Assuming an even distribution of the $575.3 million over 11 months results in monthly expenditures of $52.3 million. Applying this to the eight-month delay suggested by the RPG would result in $418.4 million in expenditures being shifted from 2014 into 2015.

530. The Commission finds that a $418.4 million reduction would not be reasonable. The RPG's calculation produced a figure of only $306.8 million. A two-month reduction would result in a reduction of $104.6 million, while a 20 per cent reduction to the total 2014 forecast expenditures of $575.3 million results in a figure of $115.1 million. Given the record of the proceeding with respect to the implementation of the EATL project, the Commission considers that a reduction of $110.0 million would be reasonable, and directs ATCO Electric, in the compliance filing, to reduce the 2014 capital expenditures for the EATL project by $110.0 million, and to eliminate the 2014 forecast capital additions for this project.

Converter stations

531. The RPG asserted that the forecast costs for the converter station costs for the EATL project were excessive, and it made the following recommendations:

- The Commission should conduct a thorough investigation to determine a reasonable capital expenditure for converter station costs.
- Until such an investigation is conducted and an improved capital forecast is determined, the forecast capital expenditures for the converter stations should be set at no more than $387.4 million, which is $94.4 million less than requested by ATCO Electric.
- ATCO Electric should be required to provide full and detailed justification for any costs incurred above the amount of $387.4 million.

- Should the Commission determine that a ceiling of $387.4 million, using a unit cost of $280/kilovolt-amperes (kVA) is too high, it should consider the other benchmark unit costs put forward by the RPG in its updated cost comparison.[241]

532. The RPG submitted that converter station costs should be no greater than $280/kVA and could be as low as $210/kVA. It is not possible to compare the cost of the 500-kV converter stations to ones previously built in Alberta because none has ever been built in Alberta. Consequently, a valid comparison has to be made to other jurisdictions where 500-kV converter stations have been built, and the RPG included such a comparison in its evidence.[242] It stated that helpful cost comparisons can be accomplished by adjusting for key differences between converter stations and other associated facilities.

533. The RPG advised that in preparing its evidence, it discussed the EATL project's converter station costs with personnel from TransGrid Solutions Ltd. (TGS), and added that TGS was unable to explain the difference between ATCO Electric's forecast costs for the EATL project's converter stations and what TGS considers to be a typical cost for such facilities. The disparity between the forecast converter station costs for the EATL project and the Western Alberta Transmission Line (WATL) project, and the costs of converter stations in other jurisdictions, is noted in a presentation made by Dr. Rashwan of TGS to the TFCMC in December 2012.

534. The RPG submitted that because of TGS's expertise in high voltage direct current (HVDC) facilities, significant weight should be given to TGS's general guideline of $180/kW to $210/kW (excluding reactive power devices like static var compensators and AC interconnection facilities). The RPG also relied on objective cost estimates produced by Black and Veatch[243] as a reasonableness test, and after adjusting for the absence of overhead costs, the resulting amount from Black and Veatch is $216/kVA.

535. The RPG identified three major cost components in order to make comparisons with other projects reasonably valid, and these are as follows:

- the cost of the converter station itself, including any AC facilities directly related to the converter station
- the cost of static var compensators and synchronous condensers (i.e. reactive power requirements)
- the cost of AC interconnection facilities required to terminate any transmission lines or cables and any civil works (such as roads, clearing, and railway access) required for these interconnection facilities

536. The RPG agreed with ATCO Electric that the static var compensators and synchronous condensers can have large variations in size and therefore can contribute to material cost differences when comparisons are made, and stated that removal of these amounts from cost comparisons will produce more valid results. It added that while the cost of the AC interconnection facilities can vary considerably depending on the AC substation design, the cost

[241] This updated cost comparison is included in Exhibit 216.02.
[242] Exhibit 103.01, RPG evidence, pages 59-61.
[243] This is included in Exhibit 110.06, Attachment 1 to the response to information request AUC-CCA-014(a).

of all AC facilities is included in both the $165/kW amount for the Power Grid Corporation of India project, and the $209/kW upgrades project from the United Kingdom. If the AC interconnection facilities costs were removed from the cost of these projects, the amount/kW would be even smaller.

537. The RPG submitted that costs associated with ATCO Electric's in-house labour to administer the turnkey contract, perform the owner's engineering role, and to hire operators and maintainers in December 2014 when the EATL project becomes operational, should also be removed when making cost comparisons.

538. Starting with the total forecast of $481.8 million for the converter stations, the RPG deducted $28.2 million for ATCO Electric's in-house labour and other costs, an estimated $20.0 million for the static var compensators, and an estimated $59.2 million for the cost of AC interconnection facilities. The resulting amount of $374.4 was then compared to the RPG's benchmark of $280.0 million with the difference being $94.4 million.

539. ATCO Electric replied that the costs of the EATL project's converter stations are largely driven by the technical requirements and the cost of construction in Alberta, and given that the EATL project will be built in Alberta, the only way to achieve a materially different outcome on costs is to radically change the operating parameters for the EATL project, and consequently the AESO's functional specifications. The AESO functional specification requires a provision to be made to accommodate a stage two expansion to 2,000 megawatts and a stage three expansion to 3,000 megawatts, and some very limited provision for multi-terminal operation. ATCO Electric submitted that all capacity in the converter station is required for initial stage one operation, and therefore will not be constructed unnecessarily early.

540. ATCO Electric countered that it would be reasonable to have cited more than two examples of actual projects to support a claim that the costs of the EATL project's converter stations are much higher than the costs in other jurisdictions worldwide. It referred to four other ongoing HVDC projects that provide a different comparison, and these projects are as follows:

- WATL with an estimated converter station cost of $539.30/kW
- Bipole III in Manitoba with an estimated converter station cost ranging from $914.25 to 1,138.50/kW
- Labrador-island transmission link between Labrador and Newfoundland with an estimated converter station cost of $517.78/kW
- HVDC pole three in New Zealand with an estimated converter station cost of $784.29/kW

541. These four projects are all higher than the EATL project's $481.77/kW, and significantly above the $180.00/kW to $210/kW rule of thumb provided by the RPG. ATCO Electric emphasized that in their presentation, Black and Veatch stated that it is imperative to note that transmission lines and substations are all unique, and the cost of a specific line or substation may be significantly different than the costs provided in the report. It submitted that the Black and Veatch report should be approached with caution.

542. ATCO Electric noted that the RPG relied on oral comments from TGS that approximately 90 per cent of the costs for the converter stations would be incurred outside of Alberta, and clarified that approximately 60 per cent of the costs for the EATL project are to be incurred in Alberta, which is far different than the 10 per cent suggested by TGS. It stated that any meaningful comparison of costs from other jurisdictions must take into account the cost of construction in Alberta compared to other areas of the world, including India.

543. ATCO Electric explained that it received comprehensive competitive bids from the three major suppliers of HVDC converter stations, in full compliance with the approved ISO rules, and that it invited alternate bids with flexible and innovative pricing and selected the lowest priced bid. It also indicated that bundling the AC facilities together with the DC facilities and including both in the turnkey project proved to be the least expensive option. Under such a turnkey contracting arrangement, there is no breakout of the detailed pricing components. ATCO Electric submitted that the costs in the turnkey contract are locked and will be incurred in accordance with the terms of the contract.

544. The RPG submitted that the WATL project's converter station costs is hardly an objective measure to judge against the EATL project's converter station costs because both projects are being developed by the same contractor, and the RPG is just as concerned that the WATL project's converter station costs are overpriced.

545. The RPG submitted that the figures for the Bipole III project provided by ATCO Electric include the cost of synchronous condensers and AC switch yards, and once these costs are excluded, the resulting cost is $280/kVA, based on a presentation made by Manitoba Hydro to the TFCMC. It also submitted that the same situation applied to the Labrador-island project, and when the cost of synchronous condensers and AC switch yards is removed, this also results in a figure of $280/kVA. It added that the HVDC pole three project in New Zealand is not a good comparator, since this project includes costs for refurbishing eight synchronous condensers, major earthquake strengthening, the replacement of the starting equipment on at least two machines, and other work as well, and unless the costs associated with these areas are removed, a valid comparison cannot be made.

546. The RPG argued that ATCO Electric's claim that 60 per cent of the costs are to be incurred in Alberta cannot be confirmed or tested as the information was only provided by ATCO Electric in very broad terms, and it is not known how much of this 60 per cent figure is comprised of materials versus labour.

547. The RPG submitted that while the outcome of a request for proposals (RFP) that involves three competitors can reflect a competitive outcome and therefore a reasonable price, there can be circumstances where the outcome of such a process does not produce a reasonable price. It used an example of designing a RFP in such a way that bidders must build in large risk premiums to manage risks that ought to be properly managed by another party. It pointed to problems with ATCO Electric's decision to bundle the AC and DC facilities into a turnkey project for both, and indicated that this eliminated western Canadian suppliers from participating in what could have been a highly competitive process for the AC facilities. It stated that ATCO Electric produced no evidence that if the turnkey project only included converter stations and reactive power requirements, and if the AC facilities had been procured separately, the pricing of the AC facilities would not have been substantially lower than what was provided in the price proposals from the three turnkey project bidders.

548. ATCO Electric submitted that the broad, high level converter station costs put forward by the RPG were done so without any detailed information being provided on these to even remotely allow for a valid comparison, and the RPG basically relied upon a review of press releases associated with these other projects to conduct a cost comparison. In addition, no evidence was presented from TGS or Dr. Rashwan and no witness was made available for cross-examination. It submitted that the WATL project serves as the best comparison for the EATL project, in that the cost information is available in a consistent format, the AESO functional specifications for both projects are identical in many respects, both are being constructed in Alberta to the same North American, Canadian and provincial regulatory requirements and industry standards, and both have a significant portion of the labour and material being locally sourced.

549. The RPG countered ATCO Electric's argument that the TGS evidence should be excluded by stating that if the TGS evidence is excluded, most of ATCO Electric's evidence, including its rebuttal evidence on converter stations, must also be excluded for the same reason.

Commission findings

550. The EATL project, which legislatively prescribes the use of DC transmission lines, must be incorporated into Alberta's existing transmission grid which is comprised of AC transmission lines. This integration is achieved through converter stations. Both parties acknowledge that ATCO Electric has no experience with this type of project. Indeed, no utility in Alberta has this experience. As such, the Commission will not attach any weight to a comparison of costs for converter stations between the EATL project and the other major transmission project concurrently directed to be completed in this province, the WATL project.

551. In the absence of any Alberta comparator information that can be relied upon to assess the reasonableness of the forecast costs for the converter stations, the Commission has considered both the comparator projects identified by the RPG and the remaining comparator projects identified by ATCO Electric. With the limited information available on the record of this proceeding regarding these comparator projects, and given the absence of expert witnesses from either the RPG or ATCO Electric who could speak to both the comparator projects and the EATL project's proposed converter station costs, the Commission can attribute very little weight to the evidence of either party respecting what a reasonable cost should be for converter stations.

552. As the RPG has itself recognized, in order to make valid comparisons with other projects, the three major components of the converter stations must be separated out. This is particularly so given the fact that the EATL project's converter stations are bundled in a turnkey project and the cost was determined through a competitive bid process. While the RPG provided material that casts some doubt on the reasonableness of the costs of the converter stations, this material, on its face, was not enough to persuade the Commission to direct the reduction requested by the RPG to the forecast converter station costs. General rules of thumb and high level benchmark comparisons are helpful in identifying potential areas of concern, and the RPG has identified a potential concern with respect to the cost of the converter stations. However, the Commission is not prepared to reduce the cost of the converter stations by $94.4 million, as proposed by the RPG.

553. The Commission reminds ATCO Electric that it bears the onus of demonstrating that the costs of its projects are reasonable, and a thorough investigation of the EATL project's costs,

including the converter station costs, will be conducted when the prudence of the final project costs for the EATL project is examined by the Commission.

11.8.3.2 Hanna Regional Transmission Development program

554. The HRTD program includes the construction of six new substations, one static var compensator, upgrades to nine substations, as well as building approximately 240 km of 240-kV lines, 110 km of 144-kV lines and 190 km of line salvage. The NID was approved by the Commission on April 29, 2010, and permits and licenses have been granted for all portions of the project. All major construction contracts have been executed. ATCO Electric provided information about the project in one business case document under Project 58005. As described in the business case, it intends to manage this program as 18 individual projects, and it provided more details about each individual project in the business case. No details with regard to the costs of each individual project were provided in the business case.

555. The forecast for this project is as follows:

Table 35. Hanna Regional Transmission Development program forecast

	2013 forecast		2014 forecast	
	Expenditures	Additions	Expenditures	Additions
	($ million)			
58005: Hanna regional transmission development	213.2	650.7	23.0	30.1

Source: Exhibit 188.02, Schedule 10-4.

556. In addition to the concerns raised with the use of third-party EPCM services for this program and the EATL project, which is addressed in Section 11.8.3.10 of this decision, the RPG made specific recommendations on the costs for labour and accommodations (camp costs) for the HRTD program.

Labour costs

557. The RPG was concerned with the significant increase in forecast labour costs when compared to the labour costs initially forecast in the AESO's authorized budget. In the July 2012 monthly progress report, the authorized labour budget was $200.1 million. The forecast is now $409.2 million. It argued that the burden of proof for demonstrating the reasonableness of forecast costs remains with the TFO for the purposes of determining revenue requirements, and that ATCO Electric has not explained, supported or justified the $209.1 million budget increase in labour.

558. The RPG submitted that the AESO requires PPS estimates to be accurate within a +20/-10 per cent range, and stated that if ATCO Electric had met this requirement, a reasonable labour cost increase would be less than $40.0 million (or 20 per cent of $200.0 million). Recognizing that the 20 per cent cost overrun is applied on the total project cost, and that individual cost components could vary by more than 20 per cent, the RPG recommended that the Commission approve no more than a 50 per cent overrun for labour. It noted that this equates to a reduction of $109.0 million, with reductions to forecast capital expenditures of $65.4 million in 2012, $37.9 million in 2013 and $5.7 million in 2014. Capital additions would be reduced by $103.3 million in 2013 and $5.7 million in 2014.

559. This issue was discussed during the oral hearing.[244] During this discussion, the ATCO Electric witnesses explained the reasons why the actual labour costs for this project are in excess of the authorized AESO budget, indicating that, because the forecast cost for the overall project was within an acceptable range of differences from the AESO budget, there was no need to request a change in the authorized budget for labour. ATCO Electric explained that the variance is due to cost escalation, contingencies, a land component that came from owner's costs, and increases in labour from higher than expected contractor costs. The ATCO Electric witnesses indicated that $60.0 million in escalation had been allocated to the labour costs and $50.0 million in contingencies had also been allocated. The witness then stated that the remaining $170.0 million variance from the PPS estimate was due to contractor cost increases.

Commission findings

560. The input figures used by the RPG to calculate the $209.1 million variance included in Figure 9 of its written argument can be traced to the July 2012 monthly progress report for this project.

561. If the Commission applies the figures of $60.0 million for escalation, $50.0 million for contingencies and $170.0 million for contractor costs provided in evidence by the ATCO Electric witness, a total variance of $280.0 million results. No explanation was provided by the ATCO Electric witnesses to explain this disparity. In addition, the record is unclear regarding the application of escalation costs. ATCO Electric stated in the application that it did not apply the 25 per cent contractor cost escalation factor to the HRTD program.

562. The record is unclear regarding what is exactly included in the latest forecast for labour for this project. An ATCO Electric witness stated that:

> A. MR. DECHAMPLAIN: There's a reallocation of -- on a particular line item compared to the estimate. So for labour, the $130 million authorized budget that you see is not a like for like with the 302 forecast final cost, because the budget included escalation and contingency, a reasonable expectation that those costs would be spent. It was included in the estimate in the plus 20 minus 10 percent estimate that we provided to the AESO.[245]

563. Given the evidence from ATCO Electric's witness that the forecast and budget labour numbers on the monthly progress report are not like for like, the Commission finds that ATCO Electric has not adequately explained what is included in the labour forecast amounts. The Commission is not persuaded that the forecast amount requested in the application is reasonable given the uncertainty on the record referenced above. The Commission agrees with the proposal of the RPG that the forecast labour costs for this project be reduced by $109.0 million, for the purposes of establishing the revenue requirement for the test years. The $109.0 million is roughly equivalent to the sum of the $60.0 million for escalation and the $50.0 million for contingencies provided by the ATCO Electric witness. The Commission does not consider that this $109.0 million should be applied to the 2013 opening CWIP balance, as this figure will be updated in the compliance filing to reflect the 2012 actuals. The Commission

[244] Transcript, Volume 4, beginning at page 830.
[245] Transcript, Volume 4, page 838, lines 12-19.

directs ATCO Electric, in the compliance filing, to reduce the 2013 forecast capital expenditures and additions for the HRTD program by $109.0 million.

Camp costs

564. In evaluating its needs for the execution of this project, ATCO Electric determined the size of the workforce needed, examined the required location for these construction resources, and then assessed the availability and the cost of local accommodations. It calculated that it would need in the order of 1.2 million man-hours of field effort to complete construction. Concluding that it was not reasonable to expect each individual contractor to provide lodgings, ATCO Electric determined that it would be necessary to provide suitable accommodations in order to attract and retain these required construction resources.

565. ATCO Electric then assessed the availability and cost of lodgings in the general area of the project. A survey confirmed that the overall capacity was inadequate and that other projects had already absorbed much of the accommodation available. In arriving at the decision to make camp facilities available, it prepared a cost/benefit analysis comparing the use of a camp versus hotels. ATCO Electric issued a tender to a number of prospective service providers and the camp contract was awarded in accordance with the tender responses, to ATCO Structures Limited.

566. The expected occupancy rate for the camp is between 90 to 100 per cent, invoices are sent directly by the provider of the camp services (ATCO Structures Limited), to ATCO Electric, and then paid once the charges have been confirmed and the actual occupancy is verified by Bechtel Canada Co. (Bechtel), who has been contracted by ATCO Electric to provide EPCM services for the HRTD program.

567. The RPG recommended that the forecast costs associated with the work camps be reduced by 25 per cent, and calculated a total reduction of $10.6 million. This results in reduced capital expenditures of $4.6 million in 2012 and $6.0 million in 2013, with a reduction to capital additions in 2013 of $10.6 million. It also recommended that in the compliance filing, ATCO Electric should be required to provide a complete analysis of the cost of these camps to demonstrate their cost effectiveness, and provide the AESO's compliance review of the HRTD program.

568. Among the concerns that the RPG raised about the work camps, were the following:

- The work camps included substantial civil works including large berms, extensive land area, perimeter fences, drainage systems and power supplies.
- No evidence was provided to show that ATCO Electric had considered whether existing motels, combined with the work camps of its construction contractors would have been a more cost effective solution.
- The inclusion of existing camps owned by construction contractors bundled together with other services would likely have been competitive compared to ATCO Electric's approach of splitting out camp costs and tendering the camps separately.
- The use of motels along the route of the transmission lines would minimize travel time and associated costs and minimize down time.
- Camp occupancy rates include rooms that an individual checks into but does not actually occupy for the night. These rooms are charged a reduced rate and incur a cost even when

service is not rendered. The extent of this pricing practice is unknown in any month other than November 2012, which was a relatively high occupancy month.

- The camps are not 100 per cent occupied throughout the project so camp charges per occupant will rise as occupancy declines, even if the daily rate is not adjusted.
- ATCO Electric claimed that its employees and those of Bechtel could not stay in the camps between August 2012 and December 2012 because camp capacity was not available; however, ATCO Electric acknowledged that occupancy levels were not high at the Hanna camp during September 2012, or during camp setup periods, since contractors were transitioning to the Oyen camp. Further, occupancy at the Oyen camp was only 51 per cent in October 2012 and only 68 per cent in November 2012. ATCO Electric did not provide an explanation as to why workers could not stay at the Hanna facility during September 2012 or at the Oyen facility during October 2012 and November 2012. ATCO Electric did not provide an explanation for the large number of hotel stays despite the availability of these work camps.
- ATCO Electric has provided no evidence to suggest that the daily camp charges per person are less than a motel occupancy rate plus meals. Hotel rates only average $113. When questioned on this matter, ATCO Electric declined to provide the information on the public record.

569. The RPG provided a calculation of the number of hotel stays that could have been avoided if Bechtel and ATCO Electric employees had stayed in the work camps.

570. The RPG submitted that although ATCO Electric had argued that it was not reasonable to expect each individual contractor to provide suitable lodgings, it had agreed under cross-examination that some contractors likely had their own camp facilities. It added that if contractors have their own camp facilities, they have these facilities to serve customers like ATCO Electric.

571. In response to ATCO Electric's submission that it had conducted a cost/benefit analysis exploring the use of camps versus hotels, the RPG countered that ATCO Electric had testified during the oral hearing that it had not completed a cost/benefit analysis in the true sense but had thought about the various cost and benefits of using work camps. The RPG argued that thinking about various costs and benefits does not amount to a cost/benefit analysis. It recommended that if ATCO Electric is now claiming to have conducted a cost/benefit analysis, the Commission should direct ATCO Electric to provide such analysis in a compliance filing, including confirmation that the cost/benefit analysis was conducted prior to the decision to tender for the work camps.

572. The RPG stated that although ATCO Electric argued that the expected occupancy rate of the work camps would be between 90 and 100 per cent, the evidence shows that actual occupancy rates were well below 90 per cent for six months of the 13 months of data provided.

573. ATCO Electric argued that the RPG provided no evidence to support its assertion that hotel accommodations were available or that the use of hotel accommodations would have been less expensive. It reiterated that it had considered the option of having individual contractors provide their own lodgings but decided that this would not be reasonable given the circumstances.

574. In response to the RPG's criticism of the agreement with ATCO Structures Limited, which resulted in charges for rooms that were on hold, ATCO Electric argued that this is a reasonable and appropriate commercial term that any contractor would demand, given that the room had been booked for the night. The contractor incurred expenses to make the accommodations available and it is appropriate that there be no free rides for parties planning to use the accommodations.

575. ATCO Electric stated that the occupancy rates at the camps are high, particularly following the ramp-up period after the camps are first available. It reiterated that it expects the occupancy rate to be in the 90 to 100 per cent range, and argued that this level of occupancy confirms the reasonableness of the accommodations. It submitted that the RPG's recommendation to decrease the camp costs by 25 per cent, is completely arbitrary, and no evidence was provided to support these recommendations.

Commission findings

576. The RPG provided no supporting calculation for its recommended reduction of 25 per cent for camp costs, and therefore the Commission has no basis to assess whether it is reasonable.

577. However, additional price and cost information respecting camp costs was provided to the Commission as part of the confidential record of this proceeding. This evidence reveals to the Commission that a reduction in the forecast for camp costs is warranted.

578. ATCO Electric must demonstrate that the rates it is being charged for the provision of camp services are reasonable, and a reasonable way to do this would be to compare the camp service rates to the rates at local hotels. ATCO Electric provided such a comparison in the confidential material, and the results showed that, on a daily basis per man, the camp service costs it was quoted as a result of the competitive tendering process were higher than the rates posted at local hotels, by an amount that was not inconsequential. This comparison included the addition of a daily allowance for meals associated with staying at hotels, in order to make the comparison valid, given that the daily camp cost rates include the cost of meals.

579. The latest forecast for camp costs of $42.2 million was provided by ATCO Electric in response to information request IPCAA-AE-019(c).[246] This includes construction costs of $21.0 million and operating costs of $21.2 million, and includes occupancy rates of 220 at Hanna, 176 at Oyen, and 132 at Consort, for a total of 528 units. In its confidential argument, the CCA submitted that this forecast cost was too high compared to the initial bid that was received from ATCO Structures Limited. The CCA's recommendation was based on comparing the cost per unit between the latest forecast and the initial bid. The Commission considers that this analysis falls short because it does not consider how long the camps in either case will be made available.

580. A better comparison would be to calculate the cost per man days available, which the CCA also provided in their confidential argument. In doing so, the CCA assumed the number of man days available at the camps. As this information was not on the record, and as ATCO Electric did not comment on the assumed number of man days that the CCA used in its calculations, the Commission cannot verify that this figure is correct. Notwithstanding, the

[246] Exhibit 54.02.

CCA's analysis showed that the latest forecast for daily camp costs was significantly higher than what was included in the initial bid. In the Commission's view, even with the limitation on the record regarding the number of man days, the variance was substantial, and enough to cast doubt on the reasonableness of the forecast camp costs.

581. ATCO Electric did not provide the details of the initial bid received from ATCO Structures Limited. All that was provided was the amount of the quote, the number of man days available, and the resulting daily rate. ATCO Electric also provided the camp services agreement dated April 19, 2012, between it and ATCO Structures Limited. The current forecast cost for the construction of the camps has increased by a significant amount when compared to the camp services agreement. Using the expected occupancy figures included in the camp services agreement, the Commission calculated the number of man days that was estimated in the preparation of the agreement, and based on the unit rates per day for an occupied room, the resulting cost corresponded closely to the estimated amount for each camp site that was included in the camp services agreement. The resulting cost per man day, based on the camp services agreement, is demonstrably higher than the cost included in the initial bid from ATCO Structures Limited. ATCO Electric has provided no explanation for the increase between the amounts included in the initial bid and the camp services agreement.

582. The Commission has calculated the difference between the resulting cost per man day in the camp services agreement and the cost per man day in the initial bid, and has applied this difference to the expected occupancy rates included in the camp services agreement. Based on the information provided and the analysis prepared, the Commission finds that the forecast camp costs have not been demonstrated to be reasonable.

583. The Commission considers that a reduction to the forecast camp costs that is generally reflective of the comparable hotel costs and expected occupancy rates is warranted, and the Commission directs ATCO Electric, in the compliance filing, to reduce the 2012 closing/2013 opening CWIP balance in the HRTD program by $8.0 million, reduce the 2013 expenditures by $2.0 million, and reduce the 2013 capital additions by $10.0 million.

11.8.3.3 North East Transmission Development

584. The NETD subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table. There are no projects forecast for this subcategory in 2014.

Table 36. North East Transmission Development forecast

	2013 forecast	
Project and description	**Expenditures**	**Additions**
	($ million)	
51718: Livock 240-kV phase shifting transformer addition	0.5	35.5
55584: Greenstocking substation	0.5	0.5
55585: North Fort McMurray Transmission Development	50.2	114.7
Total	51.2	150.7

Source: Exhibit 188.02, Schedule 10-4.

585. ATCO Electric included business cases for projects 55584 and 55585, as well as for two projects that were forecast to be completed in 2012. These two projects are 55210 – Tower road

substation, and 55631 – Quigley 144-kV line and substation. The only project that interveners raised issues with was Project 55585.

Project 55585 – North Fort McMurray Transmission Development

586. The scope of work for the North Fort McMurray Transmission Development (NFMTD) project had an original cost estimate of $195.1 million. The southern portion of the project involves constructing a 240-kV substation at Black Fly, building a 240-kV double-circuit transmission line between the Salt Creek and Black Fly substations, modifying the Salt Creek substation, and installing a 125 kW emergency diesel back-up generator at the Black Fly substation. The scope of work for the northern portion of the project includes constructing a 240-kV substation at McClelland, building a 240-kV double-circuit transmission line between the McClelland and Black Fly substations, and installing a 125 kW emergency diesel back-up generator at the McClelland substation.

587. On January 28, 2013, ATCO Electric filed a fully-approved AESO Project Trend/Change Authorization form, which approved an increase of $133.3 million to the original cost estimate for this project, and resulted in the revised cost estimate becoming $328.4 million.[247] The date of the AESO approval was January 17, 2013. The $328.4 million project is to be executed in two phases, with the latest forecast being $213.7 million added to rate base in 2012 and the remaining $114.7 million being added to rate base in 2013. The RPG pointed out that in a letter dated March 13, 2012,[248] the AESO had communicated its concerns over the revised cost estimate to the Commission.

588. The RPG submitted that the cost overruns of the NFMTD project resulted from ATCO Electric's decision to use RC22 towers instead of two single circuit transmission lines using H-frame construction, as originally approved by the Commission. After ATCO Electric decided to use the new RC22 towers, the foundation costs increased.

589. The RPG indicated that the original cost estimates for the project of $195.1 million assumed that every one of the 319 transmission towers for this project was to be installed using an H-pile foundation, which cost in the range of $96,000 to $512,000 per tower. In the updated cost estimate, 52 of the towers were revised to need a grillage foundation, which cost in the range of $300,000 to $700,000 per tower, and 64 of the towers were revised to need a caisson foundation, which cost in the range of $300,000 to $1,000,000 per tower. This upgrade in tower design resulted in an approximate increase of $75.0 million to the cost of the project.

590. The RPG submitted that the functional specification for the NFMTD project was approved on April 19, 2010, approximately 20 months before ISO Rule 502.2 came into effect, and the decision to use the RC22 tower would therefore not appear to be a requirement of the functional specification for this project.

591. The RPG argued that the decision to use the RC22 towers raises a number of questions concerning the reasonableness of the capital expenditure estimates for the NFMTD project. More specifically, it questioned what the costs for the project would have been if ATCO Electric:

[247] Exhibit 224.01, responses to questions from the RPG on undertaking responses, RPG-AE-007.
[248] Exhibit 176.01.

- had used its existing lattice structures, available at the time the functional specification was issued
- had decided to question the requirement for double circuit structures strung on one side and had proposed a single circuit H-frame structure followed by a second single circuit H-frame structure if or when required
- had decided to use double-circuit H-frame structures instead of lattice structures

592. The RPG submitted that the use of H-frame structures would likely have allowed for much faster construction, such as occurred on the 240-kV Dover-Whitefish project where 350 km were built in just four months. It added that if H-frame structures had been used, ATCO Electric would not have been affected by the shorter winter season that caused an additional $17.4 million in costs due to lack of access.

593. The RPG stated that ATCO Electric has not demonstrated the reasonableness of the cost increases for the NFMTD project, and recommended that the Commission only approve $195.1 million of capital expenditures on the NFMTD project for revenue requirement purposes. The RPG recommended that the $133.1 million disallowance all be deducted from the 2012 forecast additions for this project.

594. ATCO Electric filed a copy of the presentation it had made to the TFCMC dated February 24, 2012, relating to the NFMTD project, and indicated that this presentation thoroughly explained the cost increase in question. The main driver for the increased costs was because the geotechnical conditions actually experienced during construction were different from those assumed at the time the PPS estimate was prepared. Other additional costs arose from higher prices for major construction contracts due to higher cost tender responses, and a schedule delay due to exceptionally warm weather, which prevented access. ATCO Electric stated that the AESO has approved the completion of the project, as designed, and at all times, the AESO was kept appraised of ongoing developments through the monthly project reports that ATCO Electric filed with the AESO.

595. The RPG replied that the presentation ATCO Electric made to the TFCMC only explains the adjustments that had to be made because ATCO Electric pursued the use of the RC22 towers when other less costly options were available. If ATCO Electric had followed its historical practice in northern muskeg terrain, it should have used H-frame towers, or lattice structures, as a lower cost option.

596. The RPG submitted that even if the functional specification had compelled the use of RC22 towers, ATCO Electric could have conducted a transmission line optimization study to confirm that two H-frame circuits, or possibly other structural options such as three-pole double-circuit H-frame structures, would have a lower overall cost. If such were found to be the case, the AESO would almost certainly have changed the specifications, especially because no ISD is specified for the second H-frame circuit.

597. In response to ATCO Electric's argument that the AESO had approved the $133.1 million budget overage, the RPG submitted the following:

- Approval does not mean that the project costs were prudent. The AESO may simply have approved the overage because it was the most viable option available for mitigating an unsatisfactory situation.
- The AESO filed its March 13, 2012 letter raising concern with ATCO Electric's budget overage without signing the budget change authorization.
- The AESO did not present evidence on this matter and no AESO panel was made available for cross-examination.
- ATCO Electric's presentation on the NFMTD project provided an explanation for the additional costs, only in the sense of identifying the costs as primarily foundation-related due to actual geotechnical conditions being different than assumed; however, while the reason for the extra costs was identified, there was no evidence to establish the reasonableness of the costs. As noted in the RPG argument, drive H-Pile/screw pile foundations cost up to $512,000 per tower, grillage foundations cost up to $700,000 per tower and caisson foundations cost up to $1,000,000 per tower. These exceptionally high tower costs raise a number of questions related to their reasonableness, including the following:
    - Were the additional costs supported by change orders from the construction supplier to ATCO Electric and were the costs in the change orders fully justified?
    - Given the substantial change in the foundation requirements away from the exclusive use of H-pile foundations, was the supplier competent to also supply grillage and caisson foundations at sites where H-piles could not be used?
    - Immediately upon discovery that the geotechnical conditions were substantially different than originally assumed and could trigger exceptionally high costs:
        - Did ATCO Electric conduct a review of results of the changed geotechnical conditions to determine if a change in design, construction practice, supplier, or other factor could mitigate the cost increases?
        - Did ATCO Electric convey this information to the AESO to determine if the functional specification should be amended or other measures taken by the AESO to mitigate these additional costs?
        - Did ATCO Electric obtain additional expertise to evaluate the cost consequences of the changed geotechnical conditions to determine if there were any other options to help mitigate the extra costs?

598. The RPG submitted that these questions can only be adequately answered through a cost and performance audit of this project, and it urged the Commission to authorize one immediately.

599. ATCO Electric stated that pursuant to Section 9.1.3.5 of the ISO rules, the AESO must do one of four things detailed in this provision of the rules when confronted with a Project Trend/Change Authorization form. Based on the information provided by the AESO, including specifically its March 13, 2012 letter to the AUC, and its confirmation that, notwithstanding the increases in cost experienced, the proposed solution remains the preferred option, it should not be surprising that the other three options provided in ISO Rule 9.1.3.5 were not chosen by the AESO.

600. ATCO Electric submitted that the RPG's argument that ATCO Electric was not bound by ISO Rule 502.2 is incorrect. Although Rule 502.2 was not approved until January 2012, Section 5.2 of the NFMTD project's functional specifications[249] contains a specific reference to the ISO Transmission Line Standard Draft dated April 24, 2007. This draft standard laid the foundation for developing the details contained in Rule 502.2, and these details were developed over the period from 2007 to 2011. The NFMTD project was fully designed in 2011 when the full data from ISO Rule 502.2 was available, and therefore, these specifications were followed as required.

601. ATCO Electric submitted that the RPG misses the point that the most significant cost increase was due to the change in the scope of the foundation type that had to be used and not simply the towers themselves. More specifically, a change in foundation type was required due to the dense soil that was encountered below the top surface, which did not allow for the use of driven piles. The subsurface condition was not visible and the area was not accessible for testing at the time the initial cost estimate was developed.

Commission findings

602. As noted by the RPG, in March 2012, the AESO provided the Commission with a letter in which it advised the Commission that, pursuant to Section 25(5)(b) of the *Transmission Regulation*, it had a concern with respect to the costs of this transmission facility project. This was the first time that the AESO had chosen to take this action. The Commission shares the AESO's concern. The forecast costs of this project have increased from $195,1 million to $328.4 million and the Commission does not consider the AESO's subsequent change order approval to provide any indication as to the reasonableness or prudence of the costs of this project. That is not for the AESO to determine.

603. ATCO Electric has explained that the variance is due to the fact that it did not conduct a geological survey of the ground conditions at the time that the initial cost estimate was prepared and consequently, when the ground conditions were known to it, that vastly different and more expensive foundations were required. In addition, ATCO Electric chose to use towers that, in its view, were required to be compliant with ISO Rule 502.2, in advance of the rule coming into effect.

604. The issues raised by the RPG respecting the forecast costs for this project relate to whether it was prudent for ATCO Electric to comply with ISO Rule 502.2 in advance of the rule taking effect or whether a different design, that would have been less expensive, should have been used by ATCO Electric.

605. In sections 11.4 and 11.9.3 of this decision, the Commission has provided its views regarding the legislative requirements of TFOs to comply with ISO rules that are in effect and in these sections, the Commission has reminded ATCO Electric that it bears the onus of demonstrating the prudence of its actions when the final project costs are assessed, prior to these costs being added to its rate base. With respect to Project 55585, the Commission will, when determining the final project costs to be included in rate base for this project, assess whether it was prudent for ATCO Electric to base the functional requirements for this project on ISO Rule 502.2, including the use of RC22 towers, and whether it was prudent to do so considering when

[249] The functional specification for this project can be found in Exhibit 54.01, PDF page 963 of 1329.

ATCO Electric conducted its geological survey of the ground where the selected towers would be installed.

606. However, based on the evidence on the record, the Commission is not persuaded that the forecast costs for this project are unreasonable, given the towers used and the foundations required to install these towers with the known ground conditions. In reaching this determination, the Commission wishes to be clear that it is not making any determination regarding whether the actions taken by ATCO Electric were prudent. Consequently, the Commission rejects the recommendation of the RPG that the forecast be reduced.

11.8.3.4 North Central Transmission Development

607. The NCTD subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

Table 37. North Central Transmission Development forecast

	2013 forecast		2014 forecast	
Subcategory	Expenditures	Additions	Expenditures	Additions
	($ million)			
53320: High Prairie to Triangle 144-kV line upgrade	$23.5	$0.0	$32.9	$64.7
53720: Edith Lake transformer addition	0.6	3.9	0.0	0.0
53721: Swan River transformer replacement	0.4	5.8	0.0	0.0
53750: Edith Lake to Sarah Lake 144-kV line upgrade	10.9	18.2	0.0	0.0
54970: Otauwau 144-kV reinforcement	4.5	8.9	0.0	0.0
Total	$39.9	$36.8	$32.9	$64.7

Source: Exhibit 188.02, Schedule 10-4.

608. The NCTD program will increase available capacity to meet projected loads. It includes the construction of two substations, 68 km of 144-kV single-circuit transmission line, 11 km of 144-kV double-circuit transmission line, and two transformer upgrades, as well as the salvage of approximately 183 km of line. With regard to the final phase of the program, permit and license approval is anticipated in the first quarter of 2013, with construction beginning later in that same quarter. ATCO Electric included business cases for projects 53720 and 53721. The only project that interveners raised an issue with was 53320, for which no business case was provided by ATCO Electric.

Project 53320 – High Prairie to Triangle 144-kV line upgrade

609. As explained in its omissions and updates filing, subsequent to its initial GTA filing, ATCO Electric had provided the AESO with an updated PPS that reflects a 2014 ISD instead of a 2013 ISD, and higher project costs. ATCO Electric submitted that the project ISD has moved into 2014 as additional routing work was required to determine the final route, and the final route being proposed has wet areas that will require the 2013/2014 winter period to complete construction.

610. The RPG pointed out that the forecast cost for this project of $64.7 million included in the omissions and updates filing, had increased by $25.3 million, or 64 per cent, from the amount included in the original application, and it submitted that the explanation provided by ATCO Electric for the increase was not sufficient.

611. The RPG stated that the forecast cost per km of line for this project was $0.53 million in the original application, and using the revised forecast, the resulting cost per km is $1.09 million. It also compared the cost per km of line for this project to projects with similar design characteristics, and found that the original cost per km for the project of $0.53 million was 23 per cent higher than the Ring Creek Arcencial line completed in 2011, and 23 per cent higher than the Edith Lake to Sarah Lake line to be commissioned in 2013.

612. The RPG submitted that because routing is the only reason ATCO Electric provided for the cost increase, it is reasonable to assume that the entire cost increase is attributable to the line component of the project, and that there is no information on the record to allow any conclusion other than that a cost of over $1.0 million per km of line is excessive, unwarranted and unreasonable. It recommended that the Commission deny the cost increase proposed in the omissions and updates filing and reduce ATCO Electric's 2013 capital expenditures for this project by $23.0 million, with the same reduction to forecast capital additions in 2014.

613. ATCO Electric replied that it had provided additional information about the cost increase for this project in the project PPS estimate change proposal form,[250] and that the AESO monthly reports also detailed the cost increase and included a breakdown of such.[251] Additionally, information was provided on the unusual challenges that were encountered relative to terrain, in addition to wet conditions. Issues relating to farmer field access and a 240-kV line crossing were also identified.[252] The PPS increases are mainly due to market conditions that are expected to cause significantly higher construction costs, and the delay in the ISD is due to the time required to re-baseline the cost estimate, obtain approval, and file the facilities application with the Commission. Various route and schedule options were examined to determine if project costs could be reduced, but following a detailed assessment, it was concluded that no such savings could be achieved.

Commission findings

614. The Commission is concerned that the cost per km for this project based on the revised forecast is more than double the cost per km using the original estimate. However, this variance is only one factor to be considered when determining the reasonableness of the forecast costs for this project. Since the initial project forecast was prepared, ATCO Electric has advised that unusual challenges were encountered relative to terrain, wet conditions, field access and a 240-kV line crossing. As well, ATCO Electric explained that labour market conditions are expected to cause significantly higher construction costs. The Commission finds that the explanations provided are reasonable and therefore, the RPG's recommendation to reduce the forecast cost for this project is rejected.

11.8.3.5 Central East Transmission Development

615. The CETD program's scope of work involves the construction of two substations, modifications to 13 existing substations, building 152 km of 144-kV line, 58 km of 24-kV line, and salvaging approximately 94 km of line. The CETD subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

[250] This form is in Exhibit 230.02, PDF page 52 of 63. This form did not include an approval signature from the AESO.
[251] These monthly reports were provided in Exhibit 52.20.
[252] This information was provided in Exhibit 71.01.

Table 38. Central East Transmission Development forecast

	2013 forecast		2014 forecast	
Subcategory	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
56539: Cold Lake development	$92.7	$149.6	$0.0	$0.0
56865: Mainstream Wainwright	1.0	1.0	0.3	0.3
57102: 7L50 rebuild	6.7	0.0	55.1	0.0
57103: 7L129 rebuild	3.0	0.0	34.7	37.7
57120: Central east clearance mitigation	4.2	9.1	0.0	0.0
57150: Heisler and Kitscoty development	17.0	32.2	0.0	0.0
57151: St. Paul development	37.7	52.7	0.0	0.0
57152: Vermilion capacitor bank addition	0.4	6.6	0.0	0.0
Total	$162.7	$251.2	$90.1	$38.0

Sources: Exhibit 201.01 and Exhibit 135.01.

616. ATCO Electric included a single business case under Project 56539 which included details on each of the projects listed above, with the exception of Project 57103. On December 6, 2012, after the omissions and updates update had been filed, ATCO Electric submitted proposed revisions to the forecast capital expenditures and additions for some of its direct assigned capital projects. It stated that these revisions would be incorporated as part of the compliance filing. Included in this proposal were updates to projects 56539 and 57151.

617. ATCO Electric planned to reduce the forecast capital expenditures and additions for Project 56539 by $50.0 million in 2013, and increase the capital expenditures and additions for this project by $50.0 million in 2014. It also planned to reduce the forecast capital expenditures and additions for Project 57151 by $10.0 million in 2013, and increase the capital expenditures and additions for this project by $10.0 million in 2014. The Commission directs ATCO Electric to reflect these adjustments in the compliance filing.

618. The interveners raised issues with three projects, 56539, 57102, and 57103.

Project 56539 – Cold Lake development

619. ATCO Electric indicated that this project has three phases of construction, and a forecast ISD of quarter three of 2013.

- Phase one involves the construction of the new Bourque 970S substation, modifications to the existing Mahihkan substation and provision of an interconnection from Mahihkan to Bourque.
- Phase two involves modifications to the existing Bonnyville 700S substation with an interconnection to Bourque.
- Phase three includes modifying the Leming Lake 715S, Wolf Lake 822S and Marguerite Lake 826S substations, building approximately 16 km of 144-kV line on the new right-of-way between Marguerite and Wolf Lake, and salvaging the existing 7L87 line.

620. The RPG indicated that the cost estimate for this project at the NID stage was $76.1 million, and that the current forecast submitted by ATCO Electric of $149.6 million is based on the PPS estimate. ATCO Electric provided an explanation for the difference between these two amounts in an undertaking response.[253]

621. The RPG raised concerns with two aspects of ATCO Electric's explanation. First, the PPS estimate assumed a line length of 58 km, a 16 per cent increase over the line length at the NID stage, and the facility application indicated that the preferred route is only 53.7 km, with the alternate routes ranging from 47 km to 51 km. It submitted that ATCO Electric refused to clarify this discrepancy in response to an information request.

622. Second, the PPS estimate was prepared on the basis that the project would be built using the RC22 class of towers, which ATCO Electric indicated is required to satisfy the new ISO Rule 502.2 requirements. The RPG submitted that ATCO Electric's presumption that a new class of tower was required on the basis of ISO Rule 502.2 is incorrect, and referenced Section 2(2) of ISO Rule 502.2 in support of this statement.

623. The RPG submitted that because the effective date of ISO Rule 502.2 is January 1, 2012, any bulk transmission line with a functional specification approved by the ISO prior to January 1, 2012, must remain in compliance with the earlier dated functional specification. There appears to be no express requirement in the functional specification for the CETD program, which includes the Cold Lake development project, to adhere to ISO Rule 502.2. It stated that if the AESO had intended ISO Rule 502.2 to apply to this project, it would have expressly modified the functional specification to indicate this requirement, as it did for other specific projects.

624. The RPG argued that contrary to ATCO Electric's assertions, the functional specification does not require the use of the RC22 towers and on this basis, the forecast costs proposed for the project are unwarranted, excessive and unreasonable.

625. The RPG submitted that ATCO Electric will continue to have an opportunity to demonstrate the prudence of the higher costs related to the RC22 tower as part of the deferral account reconciliation proceeding, and it recommended that the Commission approve the expenditure forecast for revenue requirement purposes on the assumption of using the legacy tower for the 7L/9L146 portion of the project.

626. More specifically, the RPG recommended the Commission adjust the expenditure forecast in the following ways:

- inflate the NID costs estimate of $0.58 million per km for the direct costs from 2009 to 2013 dollars, using an annual inflation rate of five per cent, to produce an estimated per km cost in 2013 dollars of $0.705 million per km, and
- use a distance of 53.7 km for the line, which is consistent with the facility application

627. The RPG calculated that this results in a $20.3 million reduction to both the 2013 capital expenditures and capital additions forecast for this project.

[253] Exhibit 212.01.

628. ATCO Electric explained that it follows the Canadian Standards Association (CSA) code, as well as other applicable codes in addition to the ISO rules, when it is completing the design of transmission projects. While ISO Rule 502.2 may not have existed in final form at the time the functional specification for this project was completed, ATCO Electric was aware of it, as it had been in development since 2007. It took the information regarding the CSA code requirements, as well as the enhanced local knowledge with respect to weather loading conditions that was provided throughout the development of ISO Rule 502.2, into account, and then applied its professional judgement to arrive at the appropriate design for this project. Adhering to the old standards would not be responsible designing when the new information has resulted in enhanced local knowledge of weather loads, hence changes to tower designs.

Commission findings

629. In sections 11.4 and 11.9.3 of this decision, the Commission has provided its views regarding the legislative requirements of TFOs to comply with ISO rules that are in effect, and in these sections, the Commission has reminded ATCO Electric that it bears the onus of demonstrating the prudence of its actions when the final project costs are assessed prior to these costs being added to its rate base. With respect to Project 56539, the Commission will, when determining the final project costs to be included in rate base for this project, assess whether it was prudent for ATCO Electric to base the functional requirements for this project on ISO Rule 502.2.

630. However, based on the evidence on the record, the Commission is not persuaded that the forecast costs for this project are unreasonable, given the towers used and the foundations required to install these towers with the known ground conditions. In reaching this determination, the Commission wishes to be clear that it is not making any determination regarding whether the actions taken by ATCO Electric were prudent. Consequently, the Commission rejects the recommendation of the RPG that the forecast be reduced on this basis.

631. However, the Commission agrees with the RPG that there is no justification at this stage for the proposed line length of 58 km in the forecast, when the facility approval is based on a preferred route of 53.7 km. Using information provided by ATCO Electric in an undertaking response, in which it stated that "Included in the PPS estimate of $141 million is the 58 km line cost of $58 million, …"[254] the Commission directs that, in the compliance filing, ATCO Electric reduce the 2013 capital expenditures and 2013 capital additions for this project by $4.3 million, representing the cost associated with the extra 4.3 km of line.

Project 57102 – 7L50 rebuild

632. This project involves rebuilding existing line 7L50, which is approximately 160 km in length, from Battle River 757S substation, to Buffalo Creek 526S substation. ATCO Electric will coordinate with AltaLink on the termination of the rebuilt line to AltaLink's substations. The project is forecast to be in service by quarter four of 2017.

633. The RPG expressed concerns with respect to the timing of the expenditures and the level of costs. It referred to the latest milestone date updates for this project that ATCO Electric provided, which shows that there will be cumulative capital expenditures of $21.1 million in April 2014, which is when the facility application is projected to be filed, and cumulative capital expenditures of $62.0 million when the facility application is approved. It expected that

[254] Exhibit 212.01.

expenditures prior to the facility application being submitted and approved would be relatively minor. It also provided an analysis comparing the cost per km of a rebuild of line 7L83 planned as part of the Cold Lake development project, to the cost per km of the rebuild of line 7L50, and this analysis showed that the cost per km of the rebuild of line 7L50 is 38 per cent higher.

634. The RPG recommended that the overall expenditures for this project be reduced to $0.3 million per km to be consistent with the cost of the rebuild of line 7L83. This reduces the overall project cost to $48.0 million, which is a $14.0 million reduction to the forecast capital expenditures in 2014, and results in a remaining forecast expenditure amount of $41.1 million in 2014. It further recommended that this remaining $41.1 million be reduced by 50 per cent ($20.6 million) to shift these expenditures beyond the test period, in order to address the premature nature of the forecast provided by ATCO Electric. The sum total of these recommendations is a reduction of $34.6 million to the forecast capital expenditures for 2014.

635. ATCO Electric stated that while the AESO has requested that completion of this line be advanced to meet a 2014 ISD, ATCO Electric has recognized that this is likely not achievable and that therefore this line will be in place in 2016. The forecast expenditures included only reflect the work to be completed in the test years. It stated that this project was also discussed as part of the CETD program progress reports.

Commission findings

636. No details were provided about the total cost of this project, so the Commission cannot make any assessment of the $62.0 million forecast amount of cumulative eligible expenditures. However, the information provided by the RPG does demonstrate that ATCO Electric is forecasting to spend $40.9 million between the time the facility application is filed and the time the facility application is approved. Because ATCO Electric has stated that the line will likely not be in service until 2016, the Commission does not find this forecast amount to be reasonable.

637. The RPG has requested that a reduction in forecast costs for this project be directed on the basis of a comparison of the cost per km to the rebuild of line 7L83. Line 7L50 is approximately 160 km while line 7L83, the line relied on by the RPG as a comparator, is only 10 km in length. The Commission considers that using a comparison between these two lines is not a reasonable basis to direct a forecast reduction, because the lines may not be sufficiently similar, and the RPG's analysis is based on assumptions that have not been verified or tested.

638. The Commission finds that the forecast for 2014 should be reduced by 50 per cent, to recognize that some of the forecast expenditures are likely to be shifted into years beyond 2014. The Commission directs ATCO Electric, in the compliance filing, to reduce the 2014 forecast expenditures of $55.1 million by 50 per cent.

Project 57103 – 7L129 rebuild

639. Line 7L129 is the 144-kV line between Buffalo Creek 526S and Vermilion 710S, and the RPG noted that ATCO Electric has not provided any documentation to support the need for this rebuild. This project was not mentioned in the business case, the functional specification for the CETD program does not identify this rebuild, and the November 2012 TFCMC monthly summary report does not include this project. The RPG expressed a concern that this project is not an AESO-approved project and therefore it is premature to include it in the direct assigned capital projects forecast for the test period.

640. The RPG also expressed concerns with respect to the timing of the expenditures and the level of costs. It referred to the latest milestone date updates for this project that ATCO Electric provided, which shows that there will be cumulative capital expenditures of $9.0 million in April 2014, which is when the facility application is projected to be filed, and cumulative capital expenditures of $37.7 million when the facility application is approved.

641. The RPG recommended that the forecast expenditures of $34.7 million in 2014 and the $37.7 million forecast additions to rate base in 2014 for this project should be removed. If the Commission is not prepared to make this adjustment, then the capital expenditures forecast for 2014 should be reduced by 50 per cent ($17.4 million), and the capital additions forecast of $37.7 million in 2014 be reduced to zero, to shift these expenditures beyond the test period, in order to align with an expected ISD of 2016.

642. ATCO Electric stated that this project reflects an update regarding an additional rebuild project that it now forecasts will have to be completed in the test years. It is a component of the overall CETD program and is an example of projects that arise that were not originally contemplated.

Commission findings

643. Simply stating that this project reflects an update regarding an additional rebuild project, that ATCO Electric now forecasts will have to be completed in the test years, is not sufficient justification for the Commission to approve capital expenditures of $3.0 million in 2013 and $34.7 million in 2014.

644. ATCO Electric provided no documentation to describe this project or explain why it is necessary. In the absence of any information, the Commission finds that it would not be reasonable to include the forecast costs for this project in the test period. The Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures for this project by $3.0 million in 2013, and by $34.7 million in 2014, and to reduce the capital additions for this project by $37.7 million in 2014.

11.8.3.6 Pipeline program

645. The pipeline program subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

Table 39. Pipeline program forecast

	2013 forecast		2014 forecast	
Subcategory	Expenditures	Additions	Expenditures	Additions
	($ million)			
55322: Algar reinforcement 140/144-kV substation	8.8	0.0	29.6	39.1
55340: Dog Rib point of delivery	10.1	15.4	0.0	0.0
55622: Cheecham point of delivery	10.7	0.0	10.6	21.4
55655: Bohn point of delivery	23.5	28.1	0.1	0.1
55666: Halfway point of delivery	10.3	14.2	0.0	0.0
55785: Kettle River substation and 240-kV line tap	34.2	44.6	0.0	0.0
56052: Abee substation	0.6	7.1	0.0	0.0
56065: Weasel Creek point of delivery	0.9	17.7	0.0	0.0
56660: Beartrap 144-kV line and new substation	26.8	29.9	0.0	0.0
56665: Beartrap point of delivery	1.4	0.0	4.3	7.0
56775: Bauer 144-kV line and substation	5.6	12.1	0.0	0.0
Total	132.9	169.1	44.6	67.6

Source: Exhibit 188.02, Schedule 10-4.

646. ATCO Electric included business cases for all projects listed above with the exception of Project 56065. It also included business cases for projects 55619 (Cheecham Kinosis breaker addition), 55663 (Chard point of delivery), and 55780 (Round Hill substation interconnection). Each of these projects was forecast to be added to rate base in 2012. The only project that interveners raised an issue with was 55785.

Project 55785 – Kettle River substation and 240-kV line tap

647. The AESO has proposed to develop a new substation in the Fort McMurray area to supply a pipeline customer's pump station as well as newly proposed steam assisted gravity drainage (SAGD) facility loads. The customer has also requested that ATCO Electric provide service for the pump station by constructing the new point of delivery substation Bohn 931S. This project includes constructing the Kettle River 2049S substation, an in-out connection on the existing 9L990 transmission line, and approximately 0.5 km of double-circuit 240-kV line.

648. In the application, ATCO Electric projected an ISD of quarter four in 2013 and total forecast project costs of $21.5 million, with $4.8 million of expenditures forecast for 2012 and the remaining $16.7 million forecast for 2013. In its omissions and updates filing, ATCO Electric subsequently revised the project's total costs to $44.6 million, an increase of $23.1 million. While the application included a forecast customer contribution of $12.8 million in 2013 for this project, this was removed in the omissions and updates filing.

649. The RPG submitted that ATCO Electric had not provided any supporting information to justify the doubling of the cost of this project, and had not provided any explanation for the removal of the forecast customer contribution. It submitted that these changes, which increase

net rate base by $35.9 million, have not been properly supported, lack sufficient justification, and therefore, should be denied. It recommended a $5.6 million reduction to the forecast 2012 capital expenditures, a further reduction of $17.5 million to the forecast 2013 capital expenditures, and a $23.1 million reduction to the forecast 2013 capital additions.

650. In addition to the monthly progress reports for this project that ATCO Electric filed with the AESO and provided on the record of this proceeding,[255] it also indicated that the facilities application for this project was filed with the Commission on November 9, 2012. As part of the detailed information contained in the facilities application, an updated project cost estimate of $44.6 million was included, which provides a detailed breakdown of the forecast amounts. Since this forecast is for the "system" portion of the project only, a customer contribution is not required.

Commission findings

651. Despite the substantial increase in the forecast, the Commission considers that there is no basis to make an assessment that the revised forecast is not reasonable, especially given that ATCO Electric has included the revised forecast amount in its facilities application, which is available for interveners to examine. The forecast included in the facilities application reflects ATCO Electric's best estimate for the cost of this project, and the Commission has no basis on which to reduce this forecast. Consequently, the RPG's recommendation to reduce the forecast costs is denied.

11.8.3.7 North central region

652. The north central region subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

Table 40. North central region forecast

	2013 forecast		2014 forecast	
Subcategory	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
51184: Swan Hills synfuel generation interconnection	3.5	0.0	2.3	6.5
51103: Arcenciel synchronous condenser	10.6	43.3	0.0	0.0
51341: Buchanan Creek substation	8.5	0.0	1.6	11.1
51425: Harmon Valley point of delivery	2.5	0.0	4.7	0.0
51680: Brintnell permanent capacity addition	4.8	5.9	0.1	0.1
53032: Ksituan Range voltage regulator & 25-kV Breaker	1.7	1.9	0.0	0.0
53033: Ksituan River transformer additions	3.2	3.8	0.0	0.0
55725: Saleski	13.4	0.0	14.2	28.3
Total	48.2	54.9	22.9	46.0

Source: Exhibit 188.02, Schedule 10-4.

653. ATCO Electric included business cases for all projects listed above with the exception of Project 51341. It also included business cases for a number of other projects that were either forecast to be added to rate base in 2012 or had a work in progress balance at the beginning of 2012, but no expenditures forecast in either of 2012, 2013 and 2014. These projects are 51060,

[255] These monthly reports were provided in Exhibit 52.20.

51081, 51153, 51161, 51162, 53080, 53146, 54050, 54960 and 55721. The only project that interveners raised an issue with was 53033.

Project 53033 – Ksituan River transformer additions

654. The Baytree-Bonanza rural system and the surrounding oilfields are supplied from a single transformer at the Ksituan River substation, and should the transformer fail, approximately 26 MVA will not be served during the 12 to 14 hours required to restore service at this substation. Currently, there are no existing adjacent 25-kV tie lines between the Ksituan River substation and the adjacent substations that could provide a contingency back-up. The purpose of this project is to address reliability concerns in this area.

655. On December 6, 2012, after the omissions and updates filing had been submitted, ATCO Electric submitted proposed revisions to the forecast capital expenditures and additions for some of its direct assigned capital projects. It stated that these revisions would be incorporated as part of the compliance filing. Included in this proposal was an update to Project 53033. ATCO Electric planned to remove the 2013 forecast capital expenditures of $3.2 million for this project, as the project has been cancelled. Removing this amount will leave a balance of $0.6 million in forecast capital additions in 2013 for this project, as this represents the CWIP balance at the end of 2012.

656. The RPG indicated that the project was approved five years ago and it is concerned the development expenses booked by ATCO Electric have not been incurred reasonably or prudently. It recommended that the remaining $0.6 million of CWIP left at the end of 2012 and now forecast to be added to rate base in 2013 associated with this project be removed until such time that ATCO Electric can demonstrate the prudence of these capital expenditures in a deferral account proceeding.

Commission findings

657. The Commission agrees with ATCO Electric that the 2013 forecast capital expenditures of $3.2 million should be removed, because the project has been cancelled. Accordingly, the Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures for 2013 for this project by $3.2 million. The Commission also directs ATCO Electric, in the compliance filing, to reduce the capital additions for this project in 2013 by $3.8 million, to reduce the 2012 closing/2013 opening CWIP balance to zero, and to add the actual expenditures on this project to date into the O&M forecast costs for 2013. The Commission further directs that ATCO Electric provide, in the compliance filing, justification for the prudence of the actual capital expenditures incurred on this project to date.

11.8.3.8 North east region

658. The north east region subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

Table 41. North east region forecast

	2013 forecast		2014 forecast	
Subcategory	Expenditures	Additions	Expenditures	Additions
	($ million)			
55010: Commercial plant	$0.1	$0.0	$3.7	$0.0
55125: North west Fort McMurray area system upgrade	15.5	0.0	121.3	139.8
55147: 9L66/9L32 line relocation	0.1	0.0	5.1	0.0
55185: Deep Valley substation and line	0.5	0.0	4.4	0.0
55187: Service for MacKay SAGD	1.4	0.0	3.4	6.0
55250: Joslyn north mine 240-kV connection	3.2	0.0	12.8	0.0
55325: Algar expansion	3.2	0.0	6.3	0.0
55624: Gregoire 25-kV breaker addition	0.9	0.0	0.2	1.1
55632: Surmont II (stages 2 and 3)	34.3	34.5	11.6	15.1
55651: Egg Lake substation and 144-kV line	1.7	0.0	5.3	0.0
55662: GrMEG surmount	1.9	0.0	3.8	0.0
55680: Hangingstone SAGD	6.9	0.0	29.5	36.7
55703: Heart Lake station expansion	1.7	0.0	4.0	7.1
55737: Fort McMurray 240-kV development	0.5	0.0	2.3	0.0
55748: ATCO Dover west clastics	1.0	0.0	35.1	0.0
55750: Stone substation and line	2.0	0.0	10.0	0.0
55751: Snipe Creek substation and line	0.2	0.0	9.1	0.0
57130: Athabasca area transmission development	6.0	0.0	6.8	0.0
Total	$81.1	$34.5	$274.7	$205.8

Source: Exhibit 188.02, Schedule 10-4.

659. ATCO Electric included business cases for all projects listed above. On December 6, 2012, after the omissions and updates filing had been submitted, ATCO Electric submitted proposed revisions to the forecast capital expenditures and additions for some of its direct assigned capital projects. It stated that these revisions would be incorporated as part of the compliance filing. Included in this proposal were updates to projects 55624 and 55748.

660. ATCO Electric planned to remove the forecast capital expenditures of $0.9 million in 2013 and $0.2 million in 2014, along with the forecast capital addition of $1.1 million in 2014, for Project 55624. It also planned to increase the forecast capital expenditures in 2013 for Project 55748 by $1.0 million, and reduce the capital expenditures in 2014 by the same amount. The Commission directs ATCO Electric to reflect these adjustments in the compliance filing. The interveners raised issues with two projects, 55125 and 55185.

Project 55125 – North West Fort McMurray area system upgrade

661. This project for a 240-kV area development is to allow system interconnection for several identified customers and substation related projects located north west of Fort McMurray.

ATCO Electric is proposing three stages of development. Stage one includes the development of the new 240-kV Ells River 2079S switching station, with an initial installation of three breakers and construction of approximately 52 km of 240-kV double circuit, bundled conductor line for an in-out connection to the existing Dover/Joslyn 9L08 circuit. The proposed ISD for this is in quarter two of 2014. Stage two includes the construction of the new 240-kV Birchwood Creek switching station, and the proposed ISD is also in quarter two of 2014. Stage three includes the construction of approximately 80 km of double circuit, one side strung, bundled conductor line to interconnect Ells River to Birchwood Creek. The proposed ISD for this stage is in quarter three of 2015. The functional specification was provided in response to information request IPCAA-AE-015(c).[256]

662. The RPG made the following recommendations and requests with respect to this project.

> The Ratepayer Group therefore recommends that the transmission line component of the capital expenditure forecast for the NW Fort McMurray Transmission Development be reduced by 47% to reflect the $0.84M/km cost of single circuit H-frame construction instead of the $1.58M/km double circuit steel lattice cost used in the AE business case. The Ratepayer Group requests that the Commission direct AE to conduct a bulk line optimization study as it is required to do by ISO Rule 502.2 section 12(1)(d) and to actively engage the AESO in a cost/benefit analysis of the use of double circuit lattice steel towers in the Fort McMurray region. This analysis to be conducted with due consideration of the $133M cost overage related to the North Fort McMurray Transmission Development (see Section 10.2.2.3 herein) as well as the concerns raised regarding the additional land use and future cost risks for oil sands operators associated with double circuit steel lattice towers and their wider right-of-way.[257]

663. The RPG specifically requested that the forecast capital expenditures be reduced by $8.2 million in 2013 and $64.5 million in 2014, and that the forecast capital additions in 2014 be reduced by $72.7 million.

664. The RPG reiterated its concern with the high cost of using double circuit steel lattice structures in remote areas with poor soils. It concluded that the use of H-frame structures is more economical than the use of double circuit steel lattice structures, and that ATCO Electric's claim that the cost of a double circuit lattice steel 240-kV structure is the same as two single circuit H-frame 240-kV structures, should be rejected. It submitted that ATCO Electric's comparison was based on lines constructed on agricultural land in the Hanna area, not the Fort McMurray area. The RPG indicated that ATCO Electric is now discussing the use of H-frame structures for stage three of the project.

665. The RPG submitted that if ATCO Electric presents the AESO with all of the facts regarding the 68 per cent cost overruns on Project 55585, the NFMTD project, which has double circuit lattice tower lines, and considering the land use issues raised with respect to Project 55125, the AESO would have to agree that the single circuit H-frame is the most appropriate design for stages one and three of Project 55125.

666. ATCO Electric stated that it has addressed this matter of line design in connection with the transmission line design and optimization area of its rebuttal evidence. It added that it has a suite of structures that are the most economical to use in various circumstances, and it presently

[256] Exhibit 54.01, PDF page 451 of 1329.
[257] Exhibit 238.02, RPG argument, paragraph 147.

completes line optimization using two different processes. The total NID level estimate for this project is approximately $366.0 million, and the forecast amount to be capitalized over the test period is $139.8 million. ATCO Electric is in the process of finalizing all studies as required by ISO Rule 502.2, and any changes in the scope of this project will have no effect on the forecast for the test years, as these changes would occur in years after 2014.

Commission findings

667. In sections 11.4 and 11.9.3 of this decision, the Commission has provided its views regarding the legislative requirements of TFOs to comply with ISO rules that are in effect, and in these sections, the Commission has reminded ATCO Electric that it bears the onus of demonstrating the prudence of its actions when the final project costs are assessed prior to these costs being added to its rate base.

668. With respect to Project 55125, the Commission will, when determining the final project costs to be included in rate base for this project, assess whether it was prudent for ATCO Electric to base the functional requirements for this project on ISO Rule 502.2, including the selection of towers used, and whether it was prudent to do so considering the ground conditions where the selected towers would be installed.

669. However, based on the evidence on the record, the Commission is not persuaded that the forecast costs for this project are unreasonable given the towers proposed to be used, and the foundations required to install these towers with the known ground conditions. In reaching this determination, the Commission wishes to be clear that it is not making any determination regarding whether the actions taken by ATCO Electric were prudent. Consequently, the Commission rejects the recommendation of the RPG that the forecast be reduced.

Project 55185 – Deep Valley substation and line

670. The RPG referred to ATCO Electric's answer to a question on an undertaking response,[258] in which ATCO Electric indicated that this project was cancelled. It submitted that, based on this information, the forecast capital expenditures for 2013 and 2014 should be removed. ATCO Electric acknowledged that its forecast should have been updated to reflect the cancellation of this project and submitted that it will reflect the adjustment as part of its compliance filing.

Commission findings

671. The Commission directs ATCO Electric, in the compliance filing, to update its capital forecast by not including any opening work in progress, capital expenditures or capital additions in 2013 and 2014 for Project 55185.

[258] Exhibit 224.01, response to RPG-AE-004, line 59, note 1.

11.8.3.9 Central east region

672. The central east region subcategory is comprised of a number of individual projects, and the latest forecast is included in the following table.

Table 42. Central east region forecast

	2013 forecast		2014 forecast	
Subcategory	Expenditures	Additions	Expenditures	Additions
	($ million)			
56015: Norberg Substation and 144-kV line	11.1	14.0	0.1	0.1
56585: Taiga substation and 144-kV line	7.5	0.0	8.9	0.0
56713: Irish Creek capacity upgrade	4.2	0.0	2.9	7.3
56728: Lindbergh 25-kV breaker addition	0.6	0.0	0.2	1.0
58562: Hand Hills wind power facility	1.1	0.0	5.7	0.0
58569: Hand Hills wind power facility	0.0	0.0	1.0	0.0
Total	24.5	14.0	18.8	8.4

Source: Exhibit 188.02, Schedule 10-4.

673. ATCO Electric included business cases for all projects listed above. It also included business cases for projects 56035 (Vegreville capacity upgrade), 56360 (Nabiye generation addition), and 58842 (Wintering Hills wind farm interconnection). Each of these projects was forecast to be added to rate base in 2012. Interveners did not raise any concerns with these projects.

Commission findings

674. The forecast expenditures and additions for 2013 and 2014, as included in Table 42, are approved, except for the adjustments that are required to these projects to reflect the directions made by the Commission elsewhere in this decision, including the cost escalation reduction, the contingency reduction, and the forecast accuracy reduction.

11.8.3.10 Use of third-party engineering, procurement, and construction management services

675. Noting that ATCO Electric is using Bechtel and CIMA to provide EPCM services, the RPG expressed a concern that the extensive use of these two companies may be suboptimal and may cause unnecessary costs for ratepayers, on both the EATL project and the HRTD program. Based on the past experience with the Balfour Beatty United Group Ltd., the RPG stated that great care must be taken before outsourcing.

Use of Bechtel on the Hanna Regional Transmission Development project

676. The RPG indicated that it is possible that Bechtel has very limited or no experience in the project management of long and large transmission lines and it was concerned with the number of Bechtel staff assigned to work on the HRTD program. Further, many of the EPCM roles for ATCO Electric employees, CIMA employees and Bechtel staff on the HRTD program appear to be duplicative and excessive. Noting that there are 114 people doing EPCM services on the HRTD program in 2011, 131 in 2012 and 63 in 2013, the RPG stated that a more reasonable number of 15 to 20 people would be expected for this project.

677. The RPG indicated that a review of the unredacted business case for the decision[259] to select Bechtel to provide project management services on the HRTD program indicates that Bechtel was a higher cost option.

678. ATCO Electric referred to the documentation provide by Bechtel[260] as part of its responses to the requests for proposals for both the HRTD program and the EATL project, and stated that this provides evidence of Bechtel's significant experience. It provided an analysis which demonstrated that the costs of construction management, project management, procurement and ES&G as a percentage of total direct costs for the HRTD program is 15.4 per cent, compared to a figure of 15.6 per cent for 31 recently completed capital projects.

679. The RPG recommended that for the HRTD program, the capital expenditures be reduced by $35.0 million, consisting of reductions of $22.5 million in 2012, $10.9 million in 2013, and $1.6 million in 2014.

680. The RPG stated that there were opportunities for bias and other flaws in the selection of Bechtel for the HRTD program, and specifically noted the following:

- the evaluation of each bidder's experience was subjective and Bechtel's qualifications are not appreciably different than some of the other firms that tendered proposals
- ATCO Electric unilaterally determined to return one bid unopened when it was entirely in its discretion to determine which bids were compliant
- the weighting of evaluation criteria used to select the provider gave very little consideration to bidder pricing or fee schedules

681. The RPG stated that ATCO Electric had not produced any evidence to support its evaluation of Bechtel's tender to indicate how many, if any, of Bechtel's staff proposed for the HRTD program, had actually worked on any of the projects Bechtel listed in its experience list over the last 10 years. Considering that Bechtel's HRTD program staff may not have worked on any of the projects Bechtel listed prior to the year 2000, the project experience listed by Bechtel was not relevant in terms of justifying the selection of Bechtel. It added that only eight of Bechtel's transmission and substation projects included in its experience list were within the five year period preceding the March 2010 release of the RFP for EPCM services on the HRTD program. The RPG stated that this is a far cry from the 14 major projects with average capital equivalents to the HRTD program that were listed by another bidder, or the 5,000 km of high voltage transmission line and 200 utility substations that ATCO Electric noted as the relevant experience for another bidder.

682. Noting that ATCO Electric returned one tender unopened because it was received after the closing date, the RPG submitted that ATCO Electric likely had discretion to consider any bids that were received late. The RPG stated that it would have preferred ATCO Electric to have opened and evaluated this tender.

683. The RPG indicated that pricing received very little weight during the bid evaluation process, submitted that a weight of only 4.6 per cent was assigned to the bidders' fee schedules

[259] Exhibit 54.02, PDF page 1494.
[260] Exhibit 116.01, ATCO Electric rebuttal evidence, PDF page 170 of 229.

and budget estimates, and stated that this is completely inconsistent with ATCO Electric's statement that "pricing is a major consideration." It added that rather than accept the bidder that ranked number two technically and number one commercially, ATCO Electric further rationalized and "normalized" the bids it received, eventually allowing it to select Bechtel over the other bidders. It stated that a prudent action would have been to accept the lowest priced tender from a very well-qualified bidder, rather than Bechtel, a bid that came in some number of millions of dollars higher.

684. The RPG pointed out that although ATCO Electric revised the forecast number of hours required to design, procure, build and commission the HRTD program after the tenders had been received, there is no compelling reason that this would require ATCO Electric to revise and "normalize" the bids that had been received.

685. Referring to the analysis of the information provided by ATCO Electric, which demonstrated that the costs of construction management, project management, procurement and ES&G as a percentage of total direct costs for the HRTD program is 15.4 per cent, compared to a figure of 15.6 per cent for 31 recently completed capital projects, the RPG pointed out that by excluding ES&G the percentages are 5.7 per cent for the 31 projects versus 13.3 per cent for the HRTD program. The RPG added that a second, well-qualified EPCM services provider on the HRTD program, noted that project management services should be in the range of four to 10 per cent of the total project cost. It submitted that given the size of the HRTD program, these costs should be in the range of four to seven per cent. Applying the difference between the 13.3 per cent for Bechtel and an upper range of seven per cent, the RPG submitted that a reduction of 6.3 per cent was recommended, and applying this 6.3 per cent to the total HRTD program cost of $554.6 million results in a reduction of approximately $35.0 million.

686. The RPG submitted that the number of Bechtel personnel now currently forecast to work on the HRTD program in 2012, 2013 and 2014 is well in excess of the staffing levels that Bechtel included in its tender for this project. It produced an analysis[261] it claimed illustrates the amount of excess and redundancy between the personnel of Bechtel, ATCO Electric and CIMA.

687. Referring to the response to information request IPCAA-AE-016,[262] the RPG indicated that ATCO Electric retains overall project management and controls, including project risk and contingency management, and ATCO Electric, not Bechtel, has the majority of the project management and project controls responsibilities. Consistent with these responsibilities, the RPG submitted that the level of Bechtel's staffing for these functions should be less than that of ATCO Electric, when in fact it is not.

688. The RPG referred to the at-risk fee for Bechtel, and stated that even though ATCO Electric's business case indicates that this is a pre-determined project profit, an EPCM's contractor fee is never guaranteed for a fixed price contract, and therefore this at-risk fee is not in any way a distinguishing factor in ATCO Electric's evaluation of Bechtel's bid. It pointed out there is no indication that any of the significant budget overruns in labour costs for the transmission, substation and telecom aspects of the HRTD program will in any way affect the payout of Bechtel's at-risk fee.

[261] Exhibit 238.01, RPG argument, Volume 1, page 93, Table 6.
[262] Exhibit 54.02.

689. ATCO Electric submitted that it has significant expertise with respect to the design, construction and operation of transmission facilities, and prior to the EATL project and the HRTD program, it had routinely performed activities such as project management and construction management using extensive internal resources. While ATCO Electric had the internal expertise to perform the project management and construction management for the EATL project and the HRTD program, it simply did not have adequate resources to meet this peak demand. Given this experience, it was well equipped to determine what resources were required in order to meet the demands placed on the company by the HRTD program and the EATL project, and it put the company in an informed position to evaluate and assess bids received.

690. ATCO Electric stated that it conducted a RFP process in accordance with the ISO rules to obtain competitive bids for the provision of these services. For the HRTD program, the RFP was issued to six potential providers of the required EPCM services. Four tenders were received and a fifth was returned unopened as it was received after the closing date. It added that this is a common practice in industry, and the bid was returned in accordance with the requirements of tendering law. To do so otherwise would have constituted a disregard of such laws, which would have created significant legal exposure. It added that it specifically retained legal expertise to deal with the preparation of the bid materials, the responses received, the compliance with the bid documents and tender law, as well as the evaluation of the bids themselves. It added that it developed an extensive series of 29 evaluation criteria in order to ensure that all bids were evaluated on a consistent, fair and reasonable basis.

691. Following a thorough examination of the bids received, ATCO Electric determined that sufficient information had been provided to assess such bids on a comparable basis, as the hours and rates provided were sufficient to allow it to complete a valid comparative assessment without having to redo the entire bidding process. It determined that the hours included in the bids had been underestimated because aspects of the project were not known at the RFP stage, including issues related to changes in scope and the discovery of environmental issues. It conducted a sensitivity analysis in order to accommodate these changes and ensure that a like-for-like comparison was being conducted.

692. ATCO Electric indicated that following the technical evaluation, in conjunction with a separate assessment of the bid price submitted by each bidder, as normalized, it selected Bechtel as the EPCM contractor. It took Bechtel's extensive experience into account, as well as the systems and processes employed by Bechtel.

693. ATCO Electric submitted that the Commission must assess all of the evidence presented to determine if ATCO Electric's decisions were reasonable. It noted the following:

- it selected the party widely considered to be the best at what it does in the world with respect to the management of mega-projects
- it selected the party with the greatest technical expertise, in order to reduce execution risk and provide the greatest opportunity to achieve positive, repeatable results
- it selected the party that put forth the most favourable commercial terms, including price, that were aligned with ATCO Electric's and ratepayers' interests
- it selected the party with tried and true supporting systems that had constantly delivered positive results

694. ATCO Electric submitted that the RPG's claim that a 4.6 per cent weighting was attributed to pricing is misleading and totally inaccurate. It had a completely separate team from the technical evaluation team to assess pricing on its own.

695. ATCO Electric countered the calculation of the RPG's recommended reduction by stating that the comparison the RPG made was between EPCM costs for projects that are done internally and EPCM costs that are outsourced. In its recommendation the RPG applies its adjustment percentage of 6.3 per cent to the overall project costs, and not the costs of the EPCM services themselves. The issue at hand is the reasonableness of the EPCM contract awarded to Bechtel, not the overall project cost.

696. The RPG stated that ATCO Electric allowed Bechtel to revise its bid and selected Bechtel based on its revised rates. It indicated that it is unaware of any law that allows the tendering party to vary third-party bids after receiving them, and that the effect of normalizing the bids it received increased the bid price of bidders so that the lowest cost bid was no longer selected. The RPG submitted that this so-called normalizing of the bids cannot be seen as anything but manipulation, that ATCO Electric has violated the integrity of its bidding process, and it cannot be allowed to profit from its actions or be allowed to harm customers through such actions.

Commission findings

697. The Commission does not approve, and ATCO Electric is not required to obtain approval from the Commission, for the contracts that it enters into with service providers. ATCO Electric may enter into any contract it considers necessary, including contracts for the provision of EPCM services. The Commission will examine the reasonableness of the outcome of any contracts, as well as the reasonableness of the process ATCO Electric undertook to make the decision to enter into the contracts, when it assesses whether ATCO Electric prudently incurred costs for its projects.

698. The Commission considers that the analysis submitted by the RPG, which resulted in its recommendation to reduce the forecast EPCM costs by $35.0 million, was done at a very high level and is based on the entire project cost, not on the cost of the EPCM services included in the forecast. The high level nature of this analysis is not sufficient for the Commission to reduce the forecast EPCM costs.

699. However, the Commission shares the concerns expressed by the RPG, specifically the weight attributable to the bidder pricing or fee schedules, in the comparison and evaluation of the bids that were received. While ATCO Electric stated that it submitted a separate assessment of the bid price, ATCO Electric did not provide any information to counter the RPG's claim regarding the weighting attributable to pricing in the evaluation process. The Commission considers that the RPG's submission, which is supported by the evidence on the record, is reasonable.

700. The Commission is also concerned that ATCO Electric, after determining that the number of hours included in the bids had been underestimated because aspects of the project were not known at the RFP stage, undertook a process to "normalize" the bids. Considerable details of the events that occurred after the bids were received, including the normalization process, is included in the confidential portion of the record. The Commission considers that this

casts substantial doubt on the validity of the bids received, in respect of the new requirements, and a better course of action would have been to undertake a revised bidding process.

701. Based on its review of the record, including the confidential material, the Commission finds that it cannot draw any conclusions respecting the reasonableness of the EPCM costs on the basis of the competitive process that was pursued to select the EPCM service provider.

702. The Commission considers the percentages the RPG provided to allocate its $35.0 million recommended reduction are reasonable. These percentages are 64.3 per cent for 2012 ($22.5 million/$35.0 million), 31.1 per cent for 2013 ($10.9 million/$35.0 million) and 4.6 per cent for 2014 ($1.6 million/$35.0 million). The Commission directs ATCO Electric, in the compliance filing, for the HRTD program, to reduce the 2012 closing/2013 opening CWIP balance by $12.9 million, to reduce the 2013 forecast capital expenditures by $6.2 million, and to reduce the 2014 forecast capital expenditures by $0.9 million. In addition, the Commission directs ATCO Electric, in the compliance filing, to reduce the 2013 forecast capital additions for the HRTD program by $19.1 million, and to reduce the 2014 forecast capital additions for the HRTD program by $0.9 million.

Use of Bechtel on the EATL project

703. ATCO Electric provided a redacted business case regarding the selection of Bechtel as the project management contractor for the DC transmission line portion of the EATL project.[263]

704. The RPG referred to the following quote from the redacted business case:

> Initial analysis of the three tenders clearly showed Bechtel's man-hour estimates to be 20 closely aligned with ATCO Electric's PPS. Bechtel's estimate was approx. 10% less than that of the PPS estimate giving ATCO Electric a greater confidence in Bechtel's estimate. By comparison [Bidder X] was 60% lower than ATCO Electric's PPS estimate and the [Bidder Y] variance was even greater at 70% lower, prompting the need for a more detailed analysis. Based on a thorough review and detailed analysis of the three 25 tender responses in ATCO Electric's opinion it was very clear that only Bechtel fully understood the total scope of work required and the separation of tasks between the Owner and PMC. Neither [Bidder X] nor [Bidder Y] provided the level of staffing and total hours to successfully perform the role of PMC as describer within their proposal.[264]

705. The RPG stated that while ATCO Electric concludes that only Bechtel fully understood the total scope of work required, the business case does not address the possibility that the other two bidders could have proposed a more efficient or cost effective means for providing project management services on the EATL project. It added that Bechtel was also selected to provide project management services on the HRTD program, and a review of the unredacted business case for that decision[265] also indicates that Bechtel was a higher cost option.

706. ATCO Electric referred to the documentation provide by Bechtel[266] as part of its responses to the RFP for both the HRTD program and the EATL project, and stated that this provides evidence of Bechtel's significant experience.

[263] Exhibit 54.02,PDF page 1505 of 3838.
[264] Exhibit 54.02, PDF pages 1514 and 1515 of 3838.
[265] Exhibit 54.02, PDF page 1494.
[266] Exhibit 116.01, ATCO Electric rebuttal evidence, PDF page 170 of 229.

707. The RPG submitted that for the EATL project, it does not have sufficient specific information to calculate a recommended reduction by year. Based on the forecast cost of the transmission line component for the EATL project (for which Bechtel has been retained to provide services) of $742.0 million, and assuming that similar arrangements for the HRTD program are in place for the EATL project, using the 7.7 per cent reduction recommended for the HRTD program results in a reduction of $57.0 million for the EATL project. The RPG submitted that if the Commission considers this an appropriate reduction, it should be removed from the forecast for 2014.

708. The RPG stated that there were opportunities for bias and other flaws in the selection of Bechtel for the EATL project. Of the seven candidates that were invited to tender, only three elected to provide a bid. It submitted that there is no evidence to confirm that ATCO Electric conducted a survey or had follow-up calls with the candidates that declined to tender a bid, to determine why they decided not to bid. It stated that there is no evidence to support ATCO Electric's statement that it fully documented all of the decisions, comments, and evaluator notes relevant to the bid process. No score or comment was considered final and all recorded results were developed by group consensus, which the RPG indicated could mean that there could have been collusion or influence. The RPG stated that no individual scoring and score cards were produced for any members of the selection committee.

709. The RPG submitted that there is no evidence concerning how the evaluation of the bids for scoring purpose was separated into five weighted categories, or to show how much weighting was given to any of the five categories.

710. ATCO Electric submitted that, as with the HRTD program, it conducted a RFP process to retain expert services to assist it with the development of the EATL project. It expanded its evaluation criteria to some 47 items in order to assist in its assessment of the responses received to its RFP. Bids were solicited from seven parties, with three providing comprehensive responses. To maintain the integrity of the bid process, it developed an impartial and objective set of evaluation criteria prior to the conduct of the bid and steps were taken in order to ensure that no individual or party could influence the results of the bid or the evaluation thereof.

711. ATCO Electric reiterated the point it made in the context of the EPCM contract for the HRTD program with respect to the recommended reduction calculated by the RPG. It stated that the RPG has confused the costs associated with the EPCM for the EATL project contract with the costs for materials, equipment and services associated with the construction of the EATL project. It added that there is no evidence to support the RPG's assertions about bias in the process and the existence of collusion.

Commission findings

712. The Commission does not approve, and ATCO Electric is not required to obtain approval from the Commission, for the contracts that it enters into with service providers. ATCO Electric may enter into any contract it considers necessary, including contracts for the provision of EPCM services. The Commission will examine the reasonableness of the outcome of any contracts, as well as the reasonableness of the process ATCO Electric undertook to make the decision to enter into the contracts, when it assesses whether ATCO Electric prudently incurred costs for its projects.

713. Based on the information on the public record and the confidential material that was provided, the Commission cannot make a determination that the outcome of the process was unreasonable. Additional material will have to be provided to determine whether ATCO Electric's decision to contract the EPCM services for the EATL project to Bechtel, instead of one of the other two bidders ,was prudent, and such material should be provided as part of a subsequent deferral account proceeding for the direct assigned capital projects in which the EATL project is included.

11.8.4 Isolated generation

714. ATCO Electric monitors the condition of its isolated generation facilities and has identified capital maintenance projects required to ensure that these facilities continue to operate in a safe, reliable and environmentally responsible manner. A major new project forecast during the test period is the replacement of the engine in unit CUL 43 at Jasper Palisades due to end of life condition. The forecast for isolated generation projects is as follows:

Table 43. Isolated generation: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
90130: Refurbish/replace engines and turbines	0.7	0.7	1.0	1.0
90136: CUL 43 replacement	4.1	0.0	1.2	5.3
90140: Isolated generation capital maintenance	1.9	2.5	2.0	1.8
Total	6.7	3.2	4.2	8.1

Source: Exhibit 188.02, Schedule 10-4.

715. ATCO Electric included business cases[267] for the three projects listed above and further information was provided in response to information requests AUC-AE-027,[268] AUC-AE-043[269] and CCA-AE-035.[270]

Discussion of issues

716. No issues were raised by any of the interveners with respect to the three projects proposed. However, the CCA raised an issue with respect to a different aspect of isolated generation. As described in Section 22 of the application, ATCO Electric maintains a separate and distinct fleet of 10 emergency mobile generating units, which are utilized to provide emergency backup to the isolated generation plants. This mobile fleet is described as necessary to provide replacement generation for events that could result in extended customer outages such as fire, natural disasters, unexpected load growth, coincident unit outages, or failure of critical plant systems. ATCO Electric stated that contractor supplied mobile generating units are not viewed as a viable option, because they are not always readily available or suitable for high voltage application.

717. The CCA indicated that ATCO Electric has not provided the justification for carrying the number of mobile generating units that it carries. It added that the only evidence provided during

[267] The business case for Project 90136 is included in the business case for Project 90130.
[268] Exhibit 50.01.
[269] Exhibit 50.01.
[270] Exhibit 53.01.

the proceeding was that these units are deployed "not infrequently" and that one is currently being deployed to address a contingency in Jasper. The CCA submitted that ATCO Electric should provide, in the next GTA, information related to the frequency of usage of each of these units in each of the last five years. In addition, the CCA recommended that a properly prepared cost benefit assessment of why it would not have been cheaper to utilize contractor supplied mobile units(s) should be provided.

718. ATCO Electric rejected the CCA's recommendation and replied that its isolated generation fleet consists of a total of 46 individual generating units, with a wide variety of generating sizes, across 16 plants, and that the size and variety of the generators in the mobile fleet are directly related to the size and variety of the isolated plants. It stated that these very matters were previously addressed in recent GTAs and approved by the Commission.

Commission findings

719. A review of the list of mobile generating units, provided on page 22-4 of Section 22 of the application, shows that the oldest unit was purchased in 1974, that the most recent unit was purchased in 2003, and that the majority of the units were purchased in 1990 and 1991. The requirement for these units would have been examined and approved in previous applications, and the CCA has not demonstrated that these previous approvals should be overturned. In addition, ATCO Electric indicated that these units have been, and continue to be, frequently deployed. The CCA's request is rejected.

11.8.5 Allocated share of direct general PP&E

720. These capital projects are proposed to ensure that the tools, equipment and furnishings necessary for ATCO Electric personnel to perform their work are available. The projects also provide for routine capital maintenance on existing buildings and infrastructure. The allocated share of direct general PP&E capital project forecast is as follows:

Table 44. Allocated share of direct general PP&E: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
81000: Tools, instruments and equipment	$1.6	$1.6	$2.8	$2.8
82000: Office furniture and equipment	0.9	0.9	0.9	0.9
84000: Transportation equipment	7.0	7.0	8.5	8.5
Total	$9.5	$9.5	$12.2	$12.2

Source: Exhibit 188.02, Schedule 10-4.

721. ATCO Electric included a business case for Project 84000.

722. No objections were raised with regard to the forecast amounts.

Commission findings

723. The Commission finds the total forecast costs for these projects to be reasonable and accepts the allocation basis for these shared projects. The forecast amounts for 2013 and 2014, as

set out in Table 44, are approved, except for the adjustments that are required to these projects to reflect the directions made by the Commission elsewhere in this decision.

11.8.6 Allocated share of software projects

724. ATCO Electric explained that these various software projects are intended to ensure that the software necessary for ATCO Electric personnel to perform their work is available, that existing systems operate reliably, and that new systems, where warranted, provide efficiencies for managing an ever increasing volume of work with an increasingly inexperienced staff. The forecast is as follows:

Table 45. Allocated share of software projects: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
82407: Asset management	0.5	0.5	0.5	0.5
82409: Drawings management tool	0.6	0.6	0.0	0.0
82416: Maximo enhancements	0.1	0.1	0.1	0.1
82417: Maximo/oracle integration	0.1	0.1	0.1	0.1
82418: Project management improvements	0.3	0.3	0.3	0.3
82419: Records management	0.2	0.2	0.2	0.2
82446: Technology enhancements	0.1	0.1	0.1	0.1
82452: Windows 7 upgrade	0.8	4.1	0.0	0.0
82496: Estimation transition program	0.6	0.6	0.0	0.0
82502: Cyber security	4.6	4.6	4.5	4.5
82508: Meter attributes and readings management system	0.6	0.6	0.5	0.5
Total	8.5	11.8	6.3	6.3

Source: Exhibit 188.02, Schedule 10-4.

725. ATCO Electric included business cases for projects 82407, 82409, 82418, 82419, 82452, 82496 and 82508. Further information, including the allocation of some projects between transmission and distribution, was included in the responses to Commission information requests AUC-AE-044 to AUC-AE-050.[271]

726. No objections were raised with regard to the forecast amounts.

Commission findings

727. The Commission finds the total forecast costs for these projects to be reasonable and accepts the allocation basis for these shared projects. The forecast amounts for 2013 and 2014 as set out in Table 45, are approved, except for the adjustments that are required to these projects to reflect the directions made by the Commission elsewhere in this decision.

[271] Exhibit 50.01.

11.8.7 Allocated share of buildings

728. ATCO Electric explained that customer growth, and the associated growth in electric system infrastructure to meet this growth, are at an all-time high and expected to continue through the test period. In order to meet this growth, ATCO Electric is required to add staff in many areas to provide service across an expanded asset base and construct new utility infrastructure throughout the province. For every building project, ATCO Electric completes a detailed needs assessment and review of forecast staffing levels and requirements and, subsequently, a detailed building design and concept. In order to achieve the best value possible for the building construction, ATCO Electric tenders all building projects to a number of competent building contractors. The forecast is as follows:

Table 46. Allocated share of buildings: forecast capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
85000: Land, buildings and structures	2.7	2.7	2.7	2.7
85807: Grande Prairie regional building	0.4	0.4	0.0	0.0
85816: Drumheller service building – warehouse	1.3	2.7	0.0	0.0
85816: Drumheller service building - administration	3.0	0.0	0.7	4.7
85817: Stettler service building	0.1	0.1	0.0	0.0
85820: Peace River service building addition	3.5	3.7	0.0	0.0
85829: High Level service building	1.9	0.0	1.5	3.6
Total	12.9	9.6	4.9	11.0

Source: Exhibit 188.02, Schedule 10-4.

729. The costs of these projects are allocated between transmission and distribution. ATCO Electric included business cases for projects 85816, 85820, and 85829, and it also included a summary business case for Project 85030, the Nisku Panel shop, which was forecast to be completed in 2012.[272] Updates for projects 85807, 85816, 85817 and 85030 from the amounts provided in the 2011/2012 GRA were also provided. Further information about these projects was included in the response to information request CCA-AE-037.[273]

730. No objections were raised with regard to the forecast amounts.

Commission findings

731. The Commission finds the total forecast costs for these projects to be reasonable and accepts the allocation basis for these shared projects. The forecast amounts for 2013 and 2014 as set out in Table 46, are approved, except for the adjustments that are required to these projects to reflect the directions made by the Commission elsewhere in this decision.

11.8.8 Allocated share of corporate general PP&E

732. ATCO Electric explained that these projects comprise expenditures for office furniture, tools, instruments and equipment, and leasehold improvements. Computer systems costs relates

[272] A more detailed business case for Project 85030 was submitted in Exhibit 150.01.
[273] Exhibit 53.01.

to expenditures on corporate computer systems such as human resources systems and financial information systems. Information about the cost allocators relating to these expenditures is outlined in Schedule 27-3 of the application. The three main projects contributing to the increase in corporate general PP&E in the test period are Oracle E-Business release 12 upgrade, Oracle HRxcellence – talent management system, and Oracle business intelligence. More information about the allocations was provided in response to information request UCA-AE-022.[274] The total combined transmission and distribution forecast for this area is as follows:

Table 47. Corporate general PP&E: forecast combined capital expenditures and additions for 2013 and 2014

	2013 forecast		2014 forecast	
Project and description	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)			
81000: Tools, instruments and equipment	0.1	0.1	0.1	0.1
82000: Office furniture and equipment	0.7	0.7	0.7	0.7
82100: Software development	8.0	8.7	1.8	1.8
85200: Leasehold improvements	0.7	0.7	0.7	0.7
Total	9.5	10.2	3.3	3.3
Allocated share to transmission		4.2		1.3

Source: Exhibit 188.02, Schedule 26-2.

733. More information about the forecast capital additions for software development was provided in Schedule 26-3 of the supporting revenue requirement schedules that were filed in conjunction with omissions and updates filing.[275] Of the $8.7 million forecast capital additions for software development in 2013, $4.0 million is for Oracle E-Business, $2.1 million is for Oracle HRxcellence, and $1.0 million is for Oracle business excellence. Of the $1.8 million forecast capital additions for 2014, $1.1 million is for Oracle business excellence. Business cases were provided for these three software development projects.

734. No objections were raised with regard to the forecast amounts.

Commission findings

735. The Commission finds the total forecast costs for these projects to be reasonable and accepts the allocation basis for these shared projects. The forecast amounts for 2013 and 2014 as set out in Table 47, are approved, except for the adjustments that are required to these projects to reflect the directions made by the Commission elsewhere in this decision.

11.9 Direct assigned capital projects – common issues

11.9.1 Contingency amounts

736. ATCO Electric stated that typically, it includes a contingency amount of 10 per cent in the forecast capital expenditures for its direct assigned capital projects.

[274] Exhibit 51.01.
[275] Exhibit 188.02.

737. The ADC's evidence, prepared by Mr. Dauphinais, identified contingency amounts of $110.2 million and $193.6 million respectively, included in the 2013 and 2014 forecast capital expenditures for ATCO Electric, and the ADC recommended that these contingency amounts be excluded from the forecast. Excluding these contingency amounts would result in revenue requirement reductions of $3.4 million in 2013 and $17.2 million in 2014. The ADC explained that contingency amounts are additional amounts typically included to cover a portion of the uncertainty associated with cost estimates for projects, and added that these amounts may need to be spent due to specific uncertainties, but may not necessarily be spent. The inclusion of a contingency does not mean that that amount will in fact be spent, but rather there is a reasonable expectation that the amount may be spent. The ADC indicated that ATCO Electric will be provided an opportunity to recover any actual contingency amounts that are spent on a project when it includes the project in its direct assigned capital projects deferral account, and added that if contingency amounts are only recoverable through the deferral account, this will provide an important incentive to ATCO Electric to minimize its contingency spending.

738. ATCO Electric responded that there is a reasonable expectation that the contingency amounts will be spent, and in order to develop a capital expenditure forecast that will result in a just and reasonable tariff, it is appropriate and necessary to include contingency amounts, in accordance with Section 121(1) of the *Electric Utilities Act*.

739. The ADC responded that the word "contingency" or the words "contingency amount" are not found anywhere in Section 121 of the *Electric Utilities Act*. Further, Section 122(1) of the *Electric Utilities Act*, and not Section 121(1), specifically identifies the costs, expenses and amounts that the owner of an electric utility must be provided a reasonable opportunity to recover. The word "contingency" and the words "contingency amount" do not appear in Section 122(1) either.

740. Although the AESO reviews PPS estimates from ATCO Electric, including any contingency amounts included in the PPS estimates, the ADC stated that according to Section 25(1) of the *Transmission Regulation*, the AESO's review is explicitly limited to a determination of whether the estimates are reasonable for the purpose of making transmission system planning decisions, and does not go to the issue of whether the contingency amounts embedded in those cost estimates are reasonable to include in GTA rates prior to those amounts being actually incurred. Further, Section 25(2) of the *Transmission Regulation* states that "the ISO may satisfy itself that the cost estimates prepared by a TFO or other person under this section are reasonable, but in doing so may only examine issues that are relevant to the intended use of the cost estimates."

741. The UCA also opposed the inclusion of contingency amounts in the direct assigned capital projects expenditure forecasts, because of the existence of the direct assigned capital projects deferral account. It stated that, given ATCO Electric's history of its actual expenditures on direct assigned capital projects being less than its forecast, inflating the revenue requirement with the inclusion of contingency amounts means the current generation of customers is likely to pay amounts that will ultimately be credited to future generations of customers when the actual costs are reconciled to the forecast costs in the direct assigned capital projects deferral account.

742. ATCO Electric disagreed with the contingency amount calculation performed by Mr. Dauphinais and it provided a combined figure for 2013 and 2014 of $195.1 million as

representative of its forecast contingency costs.[276] It argued that inclusion of contingencies in capital project forecasts is a normal practice and that it is not uncommon for a portion of, or all of, a contingency to be utilized during a project's execution. It rejected any notion that attempted to differentiate between the inclusion of a provision for contingencies in a reasonable capital budget versus the inclusion of these same amounts for ratemaking purposes. ATCO Electric stated that history demonstrates that it is difficult to predict actual project costs with complete accuracy, as unforeseen events regularly occur which have an impact on project costs, and the inclusion of a reasonable contingency amount is designed to address such circumstances. It further argued that it would be unfair, and not consistent with the perspective of putting the best forecast available forward, to arbitrarily exclude all such contingencies.

Commission findings

743. Section 121(4) of the *Electric Utilities Act* provides that the burden of proof to demonstrate that a tariff is just and reasonable lies with the utility.

744. Section 122 of the *Electric Utilities Act* requires the Commission, when considering a tariff application, to have regard for the principle that the tariff that it approves must provide the owner of the utility with a reasonable opportunity to recover its costs and expenses if the Commission finds the costs and expenses to be prudent (Section 122(1)(a)) and appropriate (Section 122(1)(h)).

745. As confirmed by the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)* 2005 ABCA 122, prudent expenditures must reflect the interests of customers and avoid needless expenditures. As stated by the court in paragraph 72 of the decision:

> The Board's broad discretion to set just and reasonable utilities rates must be exercised in the public interest, which requires consideration of both sides of the rate paying equation: ATCO Electric, supra at 132. That process implicitly entails scrutiny of management decisions. With respect to negotiated settlements Fraser C.J.A. held in ATCO Electric at para. 145 that the Board "is entitled to assume that what the utility has negotiated and agreed to is in fact in the utility's best interests." However, in the context of rate setting, the starting point for scrutinizing management decisions is the presumption that it is in the utility's interest to make prudent decisions which also reflect the interests of its customers, by avoiding needless expenditure. That presumption will matter only when the scales are evenly balanced.

746. ATCO Electric has advised that it typically includes a 10 per cent contingency amount in the forecast capital expenditures of a project as a matter of practice. The Commission has considered whether ATCO Electric has demonstrated that this practice is reasonable for the purposes of its direct assigned capital projects forecast. The ADC and the UCA have argued that, because of the deferral account treatment for direct assigned capital projects, it is not reasonable to include contingency allowances in these forecasts. Rather, the ADC and the UCA contend that excluding the contingency amount in the forecast will impose a discipline on the utility to better manage its costs. This suggests that excluding the contingency amount could avoid needless expenditures for customers.

[276] Exhibit 163.01.

747. A major consideration in the Commission's decision to continue the deferral account for the direct assigned capital projects during the test period is the variability between forecast and actual costs for these projects. The balances in the deferral account are caused not only by the timing of expenditures being different than forecast, but also by the level of expenditures being different than expected. As noted by the UCA, ATCO Electric's actual expenditures on direct assigned capital projects have historically been less than its forecast.

748. Mr. Dauphinais, in his evidence stated that "… the inclusion of a contingency in a project budget does not mean that amount will in fact be spent."[277] ATCO Electric confirmed that, "In fact, it is typical that a portion, or all of, a contingency will be utilized during Project execution."[278]

749. If, as indicated by ATCO Electric, a portion and not all of the contingency amount is spent, then it is reasonable to expect that not all of the 10 per cent contingency amount that is proposed to be included in each capital project should be included in the forecast for rate setting purposes as a matter of practice. If no unforeseen events occur then no contingency amount will be spent. These unforeseen events could or could not have a material impact on the cost of the capital project, depending upon their severity.

750. Exhibit 163.01 shows that there is a large range of contingency amounts that are forecast to be included in capital expenditures in 2013 and 2014, which such range being from four per cent to 9.3 per cent. This indicates that there has been large variability in use of the contingency amounts to date in the opening CWIP balance. In the case of the HRTD program, there is a $25.7 million forecast contingency against forecast expenditures of $213.2 million in 2013 and 2014, or 12.05 per cent. Similarly, with the NETD program and the NCTD program, the contingency still available for application against the 2013 forecast is 12.3 per cent and 12.61 per cent respectively. If no contingencies arise in 2013 for these two projects then these amounts will not be spent. The 6.6 per cent number that ATCO Electric has included in Exhibit 163.01 compares the contingencies in 2013 and 2014 against the total project cost, or as indicated in the chart, Column 6 divided by Column 5. This number however computes as 5.46 per cent ($195.1 million/$3,572.8 million). The Commission finds that a more reasonable comparator is the contingency in the 2013 to 2014 period against the capital expenditures in the 2013 to 2014 period. This results in a figure of 7.42 per cent.[279] Considering that the projects mentioned are nearing completion and the expectation for unforeseen events will diminish, the Commission believes the entire $195.1 million should not be included in forecast rates.

751. The Commission concludes from this analysis that ATCO Electric has not demonstrated that it is reasonable to include a 10 per cent contingency cost as a general practice in its direct assigned capital projects forecast. Further, ATCO Electric has not demonstrated how including a 10 per cent contingency in these circumstances avoids needless expenditures for its customers, particularly given the fact that deferral account treatment for these projects will permit ATCO Electric a reasonable opportunity to recover its actual project costs that the Commission considers to be prudent and appropriate, as required by Section 122 of the *Electric Utilities Act*.

752. The Commission approves the inclusion of a five per cent contingency for the direct assigned capital projects for the test years as a reasonable forecast. The Commission directs

[277] Exhibit 88.03, page 4, lines 15-16.
[278] Exhibit 246.01, ATCO Electric reply argument, paragraph 180.
[279] $195.1 million/($1,473.8 million + $1,155.9 million).

ATCO Electric, in the compliance filing, to include only a five per cent contingency amount in the forecast capital expenditures, capital additions, and year-end CWIP balances for the direct assigned capital projects for 2013 and 2014. The Commission further directs that the compliance filing include details showing the contingency dollar amounts included for each direct assigned capital project's forecast expenditures, additions and closing CWIP balances in each of 2013 and 2014, and how this results in five percent being included for contingencies.

753. The Commission has not directed reductions with respect to any contingency amounts included in the non-direct assigned capital projects expenditures for 2013 and 2014, because this issue was not raised in this proceeding.

11.9.2 Accuracy of forecasts

754. The RPG raised a concern that the capital expenditure forecast is overly optimistic and does not reflect the high probability that some of the expenditures will be delayed. It submitted evidence that compared the applied-for capital expenditures and additions for direct assigned capital projects, to the actual amounts in each of the years 2003 to 2012. This comparison indicated a pattern of the actual amounts being less than the applied-for amounts. The RPG cited material from Decision 2012-221[280] in which the Commission commented on the accuracy of forecasts, and reliance on AESO letters of support for the direct assigned capital projects forecasts, and stated that it agrees with these observations and believes they apply in this ATCO Electric GTA as well.

755. The RPG identified a number of typical reasons why capital expenditure forecasts can be overly optimistic, and commented that when ATCO Electric was asked, in information request IPCAA-AE-011(c), about whether over a suite of several dozen projects, it is highly likely that some of those projects will get delayed for reasons within and outside the control of ATCO Electric, ATCO Electric indicated that while delays can occur on individual projects, offsetting changes to schedules can also occur for projects that experience an advancement of their schedule. The RPG reviewed the monthly reports and AESO change authorizations provided by ATCO Electric and it was able to find only one instance of schedule advancement among the more typical schedule slippages and delays. It added that this review uncovered eight transmission line projects with delayed ISDs ranging from 46 to 462 days, and 23 substation projects with delayed ISDs ranging from 64 to 821 days.[281]

756. The RPG submitted that, given the complex nature of planning, permitting and developing transmission facilities, it seems only reasonable to expect potential changes in the scope and timing of ISDs, and it provided a summary of various factors that could potentially result in a delay to a project's ISD. It offered three ways to resolve its concern that the current capital expenditures forecast for ATCO Electric is overstated, and it provided an analysis of each one. These three solutions are as follows:

- capital forecast adjustment using scenario-based probabilistic modeling
- revise the ISDs for large projects
- apply an aggregate level adjustment to the overall capital forecasts

[280] Decision 2012-221: AltaLink Management Ltd., Refiling Pursuant to Decision 2011-453 and Decision 2011-474, Application No. 1608178, Proceeding ID No. 1734, August 17, 2012.
[281] The RPG included the detailed results of its review in pages 9 and 10 of its evidence, Exhibit 103.01.

757. The RPG recommended that the third option be used, and that the aggregate level adjustment be based on the weighted average forecast variance for the years 2003-2012. This would result in a recommended reduction of 18 per cent to the 2013 and 2014 forecast capital expenditures, as well as an 18 per cent reduction to the forecast capital additions for 2013.[282] The RPG recommended that this aggregate level reduction should be applied to any projects for which it has not already requested specific adjustments.[283] It also recommended that ATCO Electric be directed to prepare the capital expenditure and capital addition forecasts in future GTAs using a method to reflect the likelihood that some projects will be materially delayed during the test period. The RPG's recommended aggregate reductions are as follows:

Table 48. Direct assigned capital projects forecast aggregate reductions recommended by the RPG

2013 forecast		2014 forecast	
Expenditures	Additions	Expenditures	Additions
($ million)			
45.0	53.0	42.0	6.0

Source: Exhibit 238.02, page 83, Figure 41. This reflects the forecast amounts included in the omissions and updates filing as well as the revision included in Exhibit 135.01.

758. ATCO Electric responded to this recommendation by submitting that its forecast capital expenditures and capital additions for direct assigned capital projects already incorporates the second solution of the RPG, and therefore an 18 per cent reduction is not required. ATCO Electric indicated that it had examined the stages of every project included in the forecast and had assessed the likelihood that each project may run into scheduling difficulties and consequential delays that would alter the forecast. It referred to the specific processes it used for developing and approving the forecast for inclusion in the GTA,[284] and advised that it grouped its forecast direct assigned capital projects into three categories, (1) advanced stage, (2) proposal stage and (3) planning stage. Applying these categories, 86 per cent of its forecast capital expenditures in 2013, and 60 per cent in 2014, were related to projects that are in the advanced stage. In contrast, in its 2011-2012 GTA, its two major projects (EATL and the HRTD program), representing two-thirds of each year's capital expenditures, were only at the planning stage.

759. ATCO Electric further indicated that, excluding the EATL project and the HRTD program, more than half of its forecast capital expenditures for direct assigned capital projects in 2013 and 2014 are for projects that primarily occupy crown land, which usually proceed quickly through the regulatory stages. It provided the average time allowances built into the forecast for all the direct assigned capital projects, with the exception of the EATL project and the HRTD program, and described some project specific examples where adjustments were made to the forecast.[285]

760. Because the RPG's weighted average variance calculation was largely based on the results from 2011 and 2012, ATCO Electric focused on these years in its rebuttal evidence. It

[282] As explained in Exhibit 114.02, the amended response to information request AUC-CCA-002.
[283] As explained in Exhibit 114.02 and demonstrated in Exhibit 114.04.
[284] These processes are described on page 10-19 of the application.
[285] These are described in Exhibit 116.01, ATCO Electric's rebuttal evidence, on page 5 of 101. They relate to Project 55125 (Northwest Fort McMurray area system upgrade), the EATL project, and Project 55622 (Cheecham).

indicated that if the 2012 forecast capital expenditures from the omissions and updates filing is used, the forecasting variance in that year is (2.1) per cent instead of the (6.7) per cent shown by the RPG. It also indicated that the 2011 variance was mainly caused by the HRTD program, and it provided more details about the delay in this project. ATCO Electric submitted that the HRTD program's variance should be adjusted due to its unique, one-time nature. When the HRTD program's variance is adjusted and the updated 2012 forecast is used, the weighted average forecast variance for the years 2003-2012 is (9.2) per cent, and with the inclusion of realistic project timelines as well as the implementation of the process improvements, forecast accuracy should only improve.

761. ATCO Electric responded to the RPG's examination of projects with delayed ISDs and indicated that of the 23 projects listed by the RPG, in 11 cases the ISD either remained as forecast, or was delayed within the year of the original ISD. The remaining 12 projects experienced delays that pushed the ISD into a subsequent year. The resulting impact on capital expenditures was a reduction of $24.7 million in 2011 with an increase of $37.0 million in 2012. This analysis did not include the HRTD program.

762. The RPG stated that one of the major reasons put forward by ATCO Electric in support of the reasonableness of its capital expenditures forecast relates to the timing for projects to proceed from PPS submission to ISD. ATCO Electric offered that for projects with forecast ISDs in 2013, it allowed an average of 22 months between the PPS submission and the ISD; and it allowed an average of 20 months for those projects with forecast ISDs in 2014. The RPG submitted that these statistics indiscriminately pool together projects with significantly different characteristics, and it added that a simple distinction is to separate projects according to size. Using a threshold of greater than $10.0 million for a large project, the RPG calculated that for large projects in 2011 and 2012, the PPS to ISD averaged 32 months as compared to only 18 months for small projects.

763. The RPG prepared an analysis which demonstrated that for large projects with forecast ISDs in the 2013 test period, the average PPS to ISD schedule included in the omissions and updates filing is 17 months, which is nearly half the time observed in the 2012 group. The results for 2014 show the average PPS to ISD being 16 months. The RPG also identified four projects for which the ISDs are in conflict between the omissions and updates filing and the information provided in Exhibit 178.01.[286] The RPG submitted that any analysis for these four projects is inconclusive because of the conflicting data. Based on the analysis it prepared, the RPG submitted that ATCO Electric's forecasting scheduling assumptions for large projects (excluding long-line projects because the 2012 comparison group does not include any long-line projects) are excessively optimistic and unreasonable.

764. The RPG also expressed a concern with the percentage of capital expenditures being forecast to occur prior to the forecasted date for facility application approvals. It submitted an analysis which demonstrated that for eight projects, ATCO Electric has forecast over 50 per cent of the capital expenditures being incurred prior to obtaining a facility approval. The RPG submitted that ATCO Electric has not provided sufficient reasons to justify this level of expenditures, and in contrast, the percentage for the other 20 projects it examined averaged 25 per cent.

[286] Exhibit 238.02, RPG argument, page 79, lines 14-17.

765. The RPG argued that, even using the 2012 forecast capital expenditure update provided in the omissions and updates filing, an adjustment was required to reflect that this was overstated by $32.0 million with respect to the EATL project. The RPG revised its weighted average variance calculation for the years 2003-2012 and the resulting amount was (17.9) per cent, which is approximately equal to the RPG's recommended reduction of 18 per cent.

766. ATCO Electric indicated that as a starting point, the direct assigned capital projects it brings forward in any given year are based primarily on the AESO's long-term plan for transmission development. It is constantly working with the AESO to develop the optimal approach to implement these projects and to recognize factors that may influence the ability to execute projects within the expected timeframe. It also assists the AESO in attempting to develop reasonable and doable ISDs for the direct assigned capital projects. ATCO Electric stated that it has been working diligently to improve its forecasting and systems, with a view to providing better forecasts in its GTAs.

767. In late 2010 and throughout 2011, ATCO Electric established a dedicated estimating group to work on improving its estimation processes and ensure continuous improvement. It has also brought increased rigour to its estimation process, which requires all aspects of the project to be considered as the project moves forward. It has incorporated realistic regulatory schedules in its forecast, based on actual experience over the past couple of years, to better determine when projects will proceed and achieve the forecast ISD. ATCO Electric referred to Exhibit 135.01, which was submitted during the oral hearing, that shows each project, by stage, and the costs associated with each such stage.[287] The majority of the projects are in an advanced stage and hence the likelihood of any material delays in project expenditures or ISDs is low.

768. ATCO Electric stated that project complexity, landowner issues and routing concerns are all taken into account when developing project cost and timing estimates, and in addition, no allowance has been made for potential new direct assigned capital projects that are likely to arise during the test period.

769. The RPG replied that ATCO Electric has done little to explain what is involved in its enhanced forecasting processes, and therefore there is no means of assessing how successful the processes have been and are likely to be in regards to the accuracy of the capital expenditures forecast. With respect to Exhibit 135.01, the RPG stated that this resulted in several material changes to the capital expenditures forecast being made on the first day of the oral hearing. It added that if the enhanced processes implemented by ATCO Electric were improving its forecasting accuracy, these changes would not have been required.

770. The RPG submitted that every time stakeholders obtained updated information from ATCO Electric, more schedule delays became apparent yet ATCO Electric claims that its latest and most current capital forecast is now accurate and will presumably not experience any more schedule slippage. It stated that ATCO Electric tends to adjust for slippage only after it is self-evident and not as a provision for something that might happen in the future, and there is no mechanism developed to recognize that some projects have a realistic probability of delay. It produced a table demonstrating that for projects where the change proposal was made to the AESO before the date of the omissions and updates filing, the schedule delays were reflected in

[287] More information with respect to Exhibit 135.01 was submitted in exhibits 178.01 and 178.02. More information with respect to exhibits 178.01 and 178.02 was submitted in exhibits 224.01 and 224.02.

the omissions and updates filing, whereas for those projects where the change proposal was made just days after the omissions and updates filing, the schedule delays were not incorporated.

771. The RPG stated that proper capital expenditure forecasts must include a mechanism to address both known and unknown risk factors and must be realistic about the impact of those risk factors. It submitted that using discrete probabilities requires considerable judgement, especially when one is forecasting matters outside of the control of ATCO Electric, such as obtaining permits and licenses when there is landowner opposition. Even if there are new projects that are likely to arise during the test period, this could be offset by the likelihood that a number of current forecast projects that are in the planning and approval stage will be delayed or cancelled.

772. ATCO Electric submitted that while the HRTD program was pointed to by the RPG as an example of a situation where ATCO Electric proactively sought and received the concurrence of the AESO to delay the project and its ISD, the RPG seeks to use this development against ATCO Electric by including it in the forecasting variance calculation.

Commission findings

773. The Commission is not persuaded that the process improvements made by ATCO Electric to enhance the accuracy of the forecast of its direct assigned capital projects during the test period, will result in the actual capital expenditures and additions being any more accurate. This is not because of any errors on the part of ATCO Electric, but because of external influences that can impact the timing and amount of capital expenditures and capital additions. These external influences, such as requests from the AESO to delay ISDs, delays in facility application proceedings, route changes, and delays in land access approval, can all impact a project's ISD. Moreover, these external influences are generally beyond the control of ATCO Electric. Recognition of these external influences factored into the establishment and continued application of a deferral account for the direct assigned capital projects by the Commission.

774. Notwithstanding ATCO Electric's efforts to improve its ability to forecast the ongoing progress of its direct assigned projects, the Commission finds that the record in this proceeding indicates that it is inevitable that there will be project delays for at least some of the direct assigned capital projects during the test period. During the processing of the application, ATCO Electric revised the original forecast for capital expenditures and additions on direct assigned capital projects more than once. It was revised as part of the omissions and updates filing, and once during the oral hearing.[288]

775. The Commission has considered ATCO Electric's position that project delays could be off-set by project advancement however, as demonstrated by the RPG's review of past projects, the Commission is not persuaded that any project advancement would be likely to off-set project delays.

776. The Commission considers that ATCO Electric's direct assigned capital projects forecast is optimistic, but accepts ATCO Electric's explanation that it is not reasonable to reduce the forecast for direct assigned capital projects by 18 per cent, as recommended by the RPG. The Commission also agrees that the weighted average forecast should be adjusted to exclude the HRTD program from the calculation. With this adjustment, and using the updated 2012 forecast,

[288] Exhibit 135.01.

the weighted average forecast variance for the years 2003 to 2012 is 9.2 per cent. The Commission considers this measure to be a reasonable proxy to employ to adjust the direct assigned capital projects forecast in recognition of the inevitable delays that can arise in the execution of direct assigned capital projects during the test years.

777. The Commission directs ATCO Electric, in the compliance filing, to reduce its direct assigned capital projects forecast capital expenditures and capital additions in 2013 and 2014 by nine per cent. This reduction should be made after applying any other reductions to the forecast capital expenditures for the direct assigned capital projects for 2013 and 2014 which have been directed by the Commission elsewhere in this decision, including the Commission's directions regarding the contingency amounts in the direct assigned capital projects forecast. The reduction should not include the milestone payments for the EATL project as discussed in paragraph 515 of this decision. Even if no other reductions have been made for a particular direct assigned capital project or group of direct assigned capital projects, the Commission directs that the nine per cent reduction be made.

11.9.3 Transmission line design and optimization

778. As noted in Section 11.4 above, the RPG is very concerned about the forecast costs for the transmission lines and the transmission towers currently expected to be used by ATCO Electric. It is concerned that ATCO Electric has not engineered its transmission projects with a view to providing the least-cost design and that ATCO Electric has not provided a sufficient cost-benefit analysis to justify the changes it is proposing to its design requirements. The RPG recommended that the Commission direct ATCO Electric to do the following:

- Conduct a study of historical failure rate of transmission structures in the province in the past 30 years and provide the corresponding reason of failure.

- Produce and make publically available the engineering studies, accompanied with the supporting meteorological studies, which supports and fully justifies the higher tower and line costs due to ATCO Electric adopting the ISO Rule 502.2 wet snow loadings for zones C and D in the ATCO Electric service territory. The studies should include a comprehensive history of 240-kV structural failures in the ATCO Electric service area, the number attributed to wet snow loading, the wet snow loading predicted by the weather model at the time of these failures, and a calculation of the probable number of tower failures which would be expected to have occurred over the last 30 years if the proposed wet snow loading conditions are an accurate representation of weather severity.

- Conduct and provide as part of the project business case submission of a GTA, a full transmission line optimization study and the associated cost assumptions as required by Section 12 of the ISO Rule 502.2, which consider a broad range of tower types and construction materials with the objective of developing the least cost design for each transmission line expected to go into service during the test period. Such a least cost design should account for all capital and operating costs.

- Develop additional standard tower designs that are more economical and suitable than the RC22 series, as may be determined through transmission line optimization studies.

- Proactively engage with the AESO in an iterative planning process to use the above information to avoid building transmission facilities that are not optimal (i.e. least cost

approaches), and that the advice and recommendations of ATCO Electric be fully documented and included as part of the project business case submission of a GTA.

- Provide the economic studies necessary for a bulk line optimization study in the compliance filing.

779. The RPG also recommended that the Commission retain a transmission line design expert to produce an independent report on line optimization, structure type selection, and the design of transmission line towers.

780. The RPG indicated that it is choosing to be proactive by raising these concerns in the context of a forecast test period and not in a deferral account proceeding, because it is more efficient and positive for all parties to deal with any material concerns before the costs are incurred. In addition, early identification of suboptimal designs allows action to be taken on any subsequent project before the same mistakes are made.

781. The RPG provided an analysis that demonstrated that the forecast cost of ATCO Electric's 240-kV transmission line projects are considerably higher than in the past, on both a $/km and a $/km-MVA basis.

782. The RPG submitted that it is entirely appropriate for TFOs to inform the AESO of opportunities to change the functional specifications of a project, and if necessary, the NID approvals, to address changes in costs or other factors relevant to a project, especially when project developments are suboptimal.

783. The RPG referenced the ISO Rule 502.2, Bulk Transmission Line Technical Requirements, and stated that changes to the tower design requirements in this rule will result in a significant increase in costs for double circuit 240-kV lines, and it provided an analysis that this cost increase will be 53 per cent. It commented that given fifty years of operating experience with the existing tower design, it is difficult to accept that tower strength must be increased by more than 50 per cent when the system has performed reliably to date. It added that optimization of each transmission line design is necessary if the lowest overall cost is to be achieved.

784. The RPG indicated that while sections 12(1)(c) and (d) of the ISO Rule 502.2 establish the requirement for a bulk transmission line optimization study or a conductor optimization study, the rule does not prescribe the objective function that is to be optimized. The RPG's expectation is that the study will determine the least-cost approach to meet the AESO's requirements set out in the NIDs. The RPG provided a description of what a line optimization study is, and what should be considered and included when it is being done.[289]

785. The RPG raised a concern about the exclusive use by ATCO Electric of bundled conductor for 240-kV lines. After evaluating the cost implications of the new wet snow loading conditions for bundled conductors, and observing that almost all of the proposed 240-kV lines utilize bundled conductor, it concluded there are potentially significant cost benefits of not using a bundled conductor. A careful analysis of the use of single conductor, in conjunction with a comprehensive line optimization study, is required for all 240-kV lines proposed and it is essential that ATCO Electric inform the AESO of these potential options in order to pursue all reasonable opportunities to minimize cost.

[289] Exhibit 103.01, RPG evidence, pages 49-51.

786. The RPG also raised a concern about the use of 240-kV double circuit towers in remote areas where the right-of-way width is not a critical concern, as it might be in more populated areas, and especially if the intention is to initially string only one side of the double circuit tower and string the second side several years later. An alternative approach is to initially build a much smaller and less costly 240-kV single circuit using an H-frame structure, and build a second circuit in the future when it is needed. The RPG also provided an analysis comparing the cost of a double circuit tower and two single circuit towers, using two scenarios of when the second circuit is built. This analysis demonstrated that building two single circuit towers had a lower cost. The RPG also included a number of other potential benefits of building two single circuit towers.[290] It submitted that a thorough analysis of this option, and other credible ones, is required, and it is essential that ATCO Electric inform the AESO of these potential options in order to pursue all reasonable opportunities to minimize cost.

787. The RPG stated that the TFOs are the designers, builders and operators of the transmission lines in the province, not the AESO, and the TFO should take an active and ongoing role in striving for the lowest possible cost, both in the design of a project as well as the execution.

788. ATCO Electric replied that it is required to follow the ISO rules and it is the AESO who completes the studies in support of its rules. It added that it follows the CSA standards when completing line designs that do not have ISO Rule 502.2 specified in the functional specification.

789. ATCO Electric explained that it presently has a suite of structures that are the most economical to use in various circumstances that it encounters. It added that it does presently complete line optimization and it does so using two distinct processes, each of which it described in more detail.[291] Utilizing a limited suite of structures, and number of conductor types, reduces overall engineering and development costs and ensures stability in O&M practices, which is critical to reducing overall costs. With respect to the RPG's suggestion regarding the RC22 series towers, ATCO Electric stated that it is presently finalizing a Zone D tower design.

790. ATCO Electric indicated that it does engage in an iterative approach with the AESO and stated that it currently submits a number of documents to the AESO, in accordance with the ISO rules. These documents, and the corresponding ISO rules, are as follows:

- NID estimates (Rule 9.1.2.1)
- PPS level estimate +20 per cent/-10 per cent (Rule 9.1.2.4)
- PPS update +10 per cent/-10 per cent 180 days after receipt of permit and license (Rule 9.1.2.5)
- project reporting and change notice (Rule 9.1.3)

791. ATCO Electric submitted that it has continuously participated in various generic processes that are conducted within the AESO's mandate, in order to ensure that the most optimal facilities are employed to meet the need identified by the AESO, and it will continue to do so.

[290] These benefits are included in Exhibit 103.01, RPG evidence, page 57.
[291] This detail is included in Exhibit 116.01, ATCO Electric rebuttal evidence, pages 28-30.

792. With respect to the RPG's recommendation that the AUC retain a transmission line design expert to produce an independent report on line optimization, ATCO Electric replied that it is the role of the AESO to produce independent reports of this nature and therefore it is not necessary for the Commission to replicate this function.

793. ATCO Electric submitted that, despite the RPG's full opportunity to participate in the process that resulted in ISO Rule 502.2, and a failure by the RPG to do so, it is now seeking to have the AESO's process vetted and purportedly changed in the context of this GTA, which is highly inappropriate. It stated that it cannot be criticized for following the ISO rules.

794. The RPG submitted that ATCO Electric:

- is purporting to follow ISO Rule 502.2 in at least two cases where there is no requirement to do so
- is needlessly incurring additional costs when there is no requirement to follow the ISO Rule 502.2
- may be incurring unnecessary costs where the ISO Rule 502.2 does apply

795. The RPG stated that the division of responsibility in the ISO Rule 502.2 is clear, and the TFO is to design each transmission line taking into account the requirement of this rule. In doing so, the TFO must account for the governing conditions (e.g. snow loading, line rating, etc.) and the TFO must conduct bulk transmission line optimization studies for 240-kV or above transmission lines with lengths of 50 km or greater. Bulk transmission line optimization studies must include consideration of both the net present value of electricity and capital costs, including the costs of structures. The RPG submitted that ATCO Electric's practice with respect to bulk transmission line optimization studies does not align with the ISO Rule 502.2. ATCO Electric restricts itself to a limited suite of structures and number of conductor types, and approaches each project and applies one of its limited options regardless of the cost. The RPG submitted that this is evident in the North Fort McMurray and Bonnyville to Bourque projects. The project requirements should determine the structure and conductor type, not the other way around. ATCO Electric's failure to even consider the use of double or single circuit H-frame structures instead of steel lattice tower structures on the North Fort McMurray and Bonnyville to Bourque projects are examples of the dangers and cost impacts of limiting choices.

796. The RPG stated that ATCO Electric provided no evidence of savings in the actual costs from using a limited suite of structures and number of conductor types, and added that these savings would have to be substantial, bearing in mind the extra $133.0 million in costs incurred on just one application of the limited menu approach.

Commission findings

797. The Commission has previously provided its views respecting optimal system design in Section 11.4 of this decision, under the sub-heading "Project design and functional specifications," and agrees that the TFOs should proactively discuss design and functional standards with the AESO with a view to minimizing costs, while ensuring an appropriate degree of reliability.

798. However, the Commission considers that some further clarification may be of assistance regarding the legislative obligations of parties under the *Electric Utilities Act* with respect to rules made by the AESO.

799. The AESO has broad statutory authority to create rules, including rules intended to establish the criteria and standards for the reliability and adequacy of the transmission system. The AESO filed its proposed ISO Rule 502.2 with the Commission on June 27, 2011, following a consultation process. The AESO requested that the ISO rule come into effect January 1, 2012.

800. No objections to the filing were received by the Commission. Accordingly, Section 20.3 of the *Electric Utilities Act* states that the ISO rule takes effect on the later of the day specified in the ISO rule and the 10th day after the day on which notice of the ISO rule is published. In this instance, the ISO rule took effect January 1, 2012.

801. Section 20.8 of the *Electric Utilities Act* requires a market participant to comply with the ISO rules that are in effect. A market participant is defined in Section 1(ee) of the *Electric Utilities Act* as any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services. Accordingly, as of January 1, 2012, ATCO Electric was required by statute to comply with ISO Rule 502.2. In the event that ATCO Electric is not complying with ISO Rule 502.2 and is required to do so for a project, it is at risk of having costs determined to be imprudent and subsequently disallowed from its rate base. Similarly, if it is determined that ATCO Electric has applied ISO Rule 502.2 to projects prematurely or improperly, ATCO Electric will have to demonstrate the prudence of its actions before those project costs will be permitted to be included in its rate base.

802. While the Commission understands why the RPG has chosen to raise, in this proceeding, an issue regarding the impact that ISO Rule 502.2 appears to be having on forecast project costs, the *Electric Utilities Act* provides specific direction to parties regarding the application of an ISO rule. If a market participant takes issue with ISO Rule 502.2, that market participant may file a complaint with the Commission pursuant to Section 25(1) of the *Electric Utilities Act*, on the grounds that the ISO rule is technically deficient; does not support the fair, efficient and openly competitive operation of the market; or that the ISO rule is not in the public interest. The Commission may, pursuant to Section 25(6) of the *Electric Utilities Act*, after hearing the complaint, confirm the ISO rule, disallow the ISO rule, or direct the ISO to change the rule or a provision of the rule.

11.9.4 Cost and performance audits

803. The RPG submitted that all transactions for direct assigned capital projects should be fully open book with total cost transparency. In order to ensure that this type of visibility into ATCO Electric's cost structure is accrued to the customers of its construction services, the RPG recommended the following:

- For all customer connection projects, provide all customers requesting interconnection facilities full contract audit rights, including verification of all labour, material, equipment, subcontract, indirect costs, unit prices, installed quantities, schedules, performance measures and other items that make up total project cost; but subject to the conditions in an audit rights clause.

- With respect to system projects initiated by the AESO, provide for an independent audit of the project costs.

    a) The independent auditor should have full contract audit rights including verification of all labour, material, equipment, subcontract, indirect costs, unit prices, installed quantities, schedules, performance measures and other items that make up total project cost but subject to the conditions in an audit rights clause.

    b) Customer representatives, including the AESO, should be able to meet with the auditor to raise any concerns they have, which would become a part of the matters investigated by the auditor.

    c) The auditor should be able to review all aspects of these projects, including the costs, schedule and technical specifications. The auditor should have appropriate experience in auditing accounting transactions but also have sufficient engineering and project management expertise to conduct a performance audit;

    d) Due to the need for the AESO to remain independent and not necessarily be involved in prudence related issues, the auditor should report to the AUC.

    e) The projects to be audited should include:

        i. All projects forecast to have total capital expenditures in excess of $100.0 million.

        ii. Smaller projects with capital costs that exceed 30 per cent of the NID estimate or 10 per cent of the PPS estimate.

        iii. Any other project designated by the AUC for an audit.

804. The RPG provided descriptions of cost and performance audits. A cost audit tests whether costs were accurately recorded in a company's project cost reports, business systems and general accounting ledgers. It checks to ensure that costs were properly supported by source documents (e.g. time sheets, expense reports, vendor invoices), that costs were actually incurred (i.e., were actually paid) and that the costs were incurred in accordance with prevailing terms and conditions of existing contract documents or purchase orders. An extensive description of a cost audit is found on pages 65 to 69 of the RPG's evidence.[292]

805. A performance audit refers to an examination of a program, function, operation, or the management systems and procedures of an entity, to assess whether the entity is achieving economy, efficiency and effectiveness in the employment of available resources. Performance audits test for the reasonableness of project charges. The examination is objective and systematic, generally using structured and professionally adopted methodologies. It uses an independent multi-disciplinary team of subject matter experts. Performance audits can be

[292] Exhibit 103.01.

proactive, as they can result in cost avoidance, as project management and control practices can be improved through the process. A detailed performance audit can also help detect fraud.

806. The RPG suggested that audit rights should be granted immediately for customer connection projects, while the Commission should administer the audits for system projects by engaging independent auditor(s), properly qualified with engineering and project management experience. Ratepayers and their representatives should have the opportunity to raise relevant concerns and issues with the Commission and auditor(s) to assist in the development of the scope of review. It is preferable to conduct cost and performance audits early and continuously. Any cost and performance auditing framework approved by the Commission should nonetheless apply to all direct assigned capital projects whose costs have not been approved by the Commission as final.

807. For customer connection project audits, the specific customer being connected would have the option to audit and the obligation to pay, and for system projects, the costs should be included in transmission system costs and recovered through the AESO's tariff. This treatment is reasonable, as the cost savings on system projects will benefit all transmission system users/ratepayers. Based on Mr. Mohr's testimony, the RPG anticipates that the cost savings will more than offset the cost of conducting audits.

808. ATCO Electric submitted that there is no need for additional audit scrutiny given the following checks:

- ATCO Electric's internal controls
- ATCO Electric's processes used to work with customers
- existing AUC audit function
- existing AESO audit function
- AESO approval of the reasonableness of costs at the PPS stage
- AESO approval of project change requests
- AUC and intervener review of reasonableness of forecast costs as part of the GTA
- ongoing monitoring by the TFCMC
- prudence reviews completed by the AUC as part of the deferral application proceedings
- further, the AESO proposed to work with the AUC to develop a Transmission Project Reporting and Oversight Protocol to ensure the above processes meet the needs of all interested parties

809. Given these checks, additional audits would be duplicative and redundant. ATCO Electric indicated that it has internal control procedures that address construction audit issues, and it added that it will be conducting internal contract reviews similar to those described in the response to information request AUC-AE-016,[293] thereby obviating the need for customers to incur additional charges for external audits of the same nature. It also has an internal audit department that is responsible for ensuring that internal control processes are properly

[293] Exhibit 110.01.

implemented and followed. It added that it currently works with all customers requesting interconnection facilities to ensure that issues relating to cost and schedule are resolved.

810. ATCO Electric listed five projects that have been subject to compliance audits by the AESO, filed audit reports on the record for three of these projects, and advised that audits on the other two are currently underway.[294] It indicated that the Commission also has the ability to audit TFOs, and mentioned that the TFCMC provides an ongoing monitoring function for all projects exceeding $100.0 million. ATCO Electric also pointed out that the Commission and interveners are able to participate in a process for determining the prudence of all project costs, as part of its GTAs and deferral account applications.

811. ATCO Electric stated that the AESO and the Commission are already involved in developing an industry reporting protocol, and the Commission has confirmed that broad industry wide consultations will occur regarding this matter.

812. The RPG stated that the checks listed by ATCO Electric do not in any way replace or substitute for the cost and performance audits it has recommended. It addressed each of the checks in its written argument.[295] It also referenced paragraphs 476 to 479 of Decision 2009-151[296] where the issue of audit rights was raised, and it stated that internal and external controls remain inadequate. It submitted that role of cost and performance audits in the context of a TFO monopoly should be seen as a reasonable substitute for the role that competition plays in a competitive industry. It added that cost and performance audits have the potential to reduce the need for, or certainly the length of, regulatory proceedings, which streamlines the regulatory process.

813. The RPG stated that for some time, ratepayers have requested and recommended detailed audits of TFO's EPCM costs, but the Commission has yet to develop a rule or other specific process to protect ratepayers in this regard. For this reason, it felt compelled to again seek the further and better relief provided by cost and performance audits. It submitted that the independent review, verification and the potential adjustment of costs that might arise from such a process is in the public interest.

814. The RPG submitted that the decision to perform an audit and the scope of the audit itself are not generic in nature. There has already been far too much delay in implementing cost and performance audits and ATCO Electric's attempt to further postpone the Commission's implementation of audits for ATCO Electric is not in the public interest. A generic process risks consuming yet more time before rules can be established on an industry wide level, and waiting for a rule based process is completely unreasonable, unfair and prejudicial to ratepayers. Further delay will mean losing the opportunity to proactively audit cost and performance for ATCO Electric's unprecedented level of capital expenditures. Cost and performance audits are not being performed in the existing processes and therefore they are not duplicative or redundant.

815. The RPG submitted that currently customers have no way to ensure that there is diligent adherence to ATCO Electric's internal policies and procedures, and an external audit would provide much more assurance that incurred costs are prudent. It pointed out that the most recent

[294] As listed in Exhibit 116.01, ATCO Electric rebuttal evidence, paragraph 156.
[295] This information is in Exhibit 238.01, RPG argument, paragraphs 196-219.
[296] Decision 2009-151: AltaLink Management Ltd. and TransAlta Corporation, 2009 and 2010 Transmission Facility Owner Tariffs, Application Nos. 1587092, 1594573, Proceeding ID. 102, October 2, 2009.

Commission audit report for ATCO Electric was dated November 2009. For capital projects in industry, where contractor compensation is based on the cost of the work, parties obligated to pay for these costs typically have an opportunity to review and confirm or obtain independent verification of their reasonableness, necessity and actual incurrence. The RPG filed a typical audit rights clause for a cost plus contract as part of its evidence,[297] and added that ATCO Electric has a somewhat similar clause in its own construction services template. Provisions to facilitate cost accountability observed in ATCO Electric's template contracts with its suppliers should be mirrored in customer's relationships with ATCO Electric.

816. The RPG submitted that stakeholders involved in a construction project need assurance that project costs are reasonable, billed in accordance with contract terms, and were actually incurred, and that it is essential that audit rights be given to all stakeholders.

Commission findings

817. The Commission has also commented generally on audits in Section 11.5 of this decision, under the sub-heading "Audits of transmission project expenditures." The Commission considers that in general, audits are beneficial in that they provide an independent check with regard to the capital costs that have been recorded in a company's books of account for capital projects. This will help to add assurance that the capital project costs ratepayers are being asked to pay for are properly supported. However, the Commission is not prepared at this time to make such audits mandatory for all capital projects that have a cost in excess of $100.0 million. The costs and benefits of conducting audits on this basis are not well understood, based on the record of this proceeding. Notwithstanding, considering the sizable capital projects forecast to be constructed over the next few years, the Commission finds that it would be instructive and in the public interest to select one project for an audit. Depending on the results of that audit, a process may be initiated to determine the requirement or need for future audits.

818. The RPG has requested that the Commission reserve the right to conduct cost and performance audits on two capital projects included in the 2011 direct assigned capital projects deferral account: Sulphur Point – High Level 144-kV line (Project 51060) and Ring Creek Arcenciel – 144-kV line and substation (Project 51081). The capital cost of the Sulphur Point – High Level project is $28.4 million, while the Ring Creek Arcenciel project has a capital cost of $65.2 million. Neither of these projects is in excess of the $100.0 million threshold that the RPG suggested and the Commission considers that neither of these projects is large enough to represent a good example for an initial audit. Therefore, the RPG's request that the Commission reserve the right to conduct cost and performance audits on these two projects is denied.

819. The Commission considers that a better candidate for an audit would be the entirety of the HRTD program, because this program has a forecast capital cost in excess of $740.0 million.[298] The Commission directs that an audit, under the direction of the Commission, be carried out with respect to the HRTD program, once the program is fully complete. The Commission will provide specific details regarding the audit scope, audit plan, selection of the independent auditor, and materiality limit in due course. Considering that this audit will be for the entirety of the HRTD program, capital additions for the HRTD program in each year of 2011, 2012, 2013 and 2014 will be approved as placeholders, until the audit is complete.

[297] Exhibit 103.01, RPG evidence, pages 63 and 64.
[298] Exhibit 188.02, Schedule 10-4: 2011 capital additions of $5.6 million, 2012 capital additions of $54.6 million, 2013 capital additions of $650.7 million and 2014 capital additions of $30.1 million.

11.9.5 Inter-affiliate code of conduct

820. The ATCO Electric inter-affiliate code of conduct does not apply to services purchased from an affiliate of ATCO Electric by a third-party contractor, even if those services are obtained by the third-party contractor to provide services to ATCO Electric. The RPG submitted that as a result, these transactions are only subject to self-policing with regard to whether they qualify as fair and competitive practices. In essence, working through a sub-contractor, ATCO Electric has the freedom to do indirectly what it cannot do directly due to the inter-affiliate code of conduct. The RPG used an example that a sub-contractor like Bechtel is not required to transact with an ATCO Electric affiliate at fair market value.

821. The RPG made the following recommendations:

- The Commission should rule on the application of the present inter-affiliate code of conduct with respect to transactions between ATCO Electric's contractors and ATCO Electric's affiliates.
- Should there be a need to revise the inter-affiliate code of conduct, the Commission should direct the revision.
- Assuming a revision is necessary, during the interim, while the changes are underway, the Commission should protect ratepayers through a directive to ATCO Electric to provide full disclosure of all transactions between ATCO Electric and a contractor whenever that contractor does business with an ATCO Electric affiliate; and documentation should be provided to demonstrate that all the relevant transactions have not resulted in any cross-subsidization.

822. ATCO Electric replied that Section 7.2 of the inter-affiliate code of conduct requires it to communicate the code to contractors, and Section 7.5 of that document requires that ATCO Electric prepare a compliance plan detailing how it will ensure its full compliance with the code, including its contractors. ATCO Electric's contractors provide a written acknowledgement that they will abide by the code's requirement. It added that for the HRTD program, Bechtel is required to transact at arm's length and for fair market value with any of ATCO Electric's affiliates. In addition, when ATCO Electric hires project contractors, there are no explicit or implicit requirements that the contractor transact with ATCO Electric's affiliates, and there are no cases where a contractor's transaction with an ATCO Electric affiliate have resulted in cross-subsidization.

823. ATCO Electric submitted that no evidence of any wrongdoing in this regard was brought forward. It stated that it has been governed by the inter-affiliate code of conduct for an extended period of time and it is required to address code of conduct issues annually and make compliance filings with the Commission.

824. The RPG submitted that the purpose of the inter-affiliate code of conduct is to prevent misconduct beforehand, and the mere prospect of wrongdoing should be sufficient for the Commission to review the code and to determine if it needs to be revised to address contracting relationships not previously considered. The public interest is at risk if the condition for revising the code first requires the demonstration of wrongdoing.

Commission findings

825. Although independent contractors are not bound by the inter-affiliate code of conduct, ATCO Electric's contractors provide a written acknowledgement that they will abide by the requirements of the code. The RPG has not brought forward any evidence of wrong-doing or collusion in the relationships between ATCO Electric, its contractors and affiliates of ATCO Electric, to avoid the application of the requirements of the code despite ATCO Electric having been subject to the requirements of the inter-affiliate code of conduct for many years. Consequently, the Commission is not prepared to conclude that the public interest requires that the Commission conduct a review of the inter-affiliate code of conduct provisions at this time. The RPG's request is denied.

11.10 Net salvage

826. ATCO Electric forecast $1.4 million in 2013 and $2.0 million in 2014, for net salvage credits that are applied against the cost of capital additions during the test period.[299]

827. No parties raised any issues with respect to these forecasts.

Commission findings

828. Although the forecasts of $1.4 million in 2013 and $2.0 million in 2014 are smaller than the actual amounts for 2010 and 2011 of $3.0 million and $2.5 million respectively, they are commensurate with the 2012 updated forecast amount of $1.4 million. These forecast amounts are insignificant with respect to the forecast capital additions of approximately $1.5 billion in 2013 and $2.2 billion included in Table 2 of this decision, and an adjustment to reflect the actual amounts for 2010 and 2011 would not result in a material impact on the forecast revenue requirements for 2013 and 2014. Therefore, the net salvage credit amounts of $1.4 million in 2013 and $2.0 million in 2014 are approved as filed.

11.11 Engineering, supervision and general costs and rate

829. ES&G costs generally include costs that support all capital projects. Examples include rent, computer system charges, drawing and other project document management, and the development and maintenance of engineering standards. These are analogous to overheads that would normally be charged by a contractor hired to engineer, procure and construct similar projects. ATCO Electric includes other charges in ES&G, such as general supervision and training for employees engaged primarily in capital work that a contractor would typically charge directly to the cost of large jobs. Details of the updated total forecast ES&G costs for 2013 and 2014, as well as the ES&G rate that is applied to all capital expenditures with the exception of software projects) are included in Schedule 10-6 of the supporting revenue requirement schedules that were filed in conjunction with omissions and updates filing.[300] These forecast amounts are as follows: 2013 – total costs of $52.3 million and a rate of 3.5 per cent, 2014 – total costs of $55.6 million and a rate of 4.9 per cent. More information was provided in response to information requests UCA-AE-026[301] and CCA-AE-025.[302]

[299] Exhibit 188.02, Schedule 10-4: line 362 ($1.2) million plus line 406 ($0.2) million equals ($1.4) million for 2013. Line 519 ($1.8) million plus line 544 ($0.2) million equals ($2.0) million for 2014.
[300] Exhibit 188.02.
[301] Exhibit 51.01.
[302] Exhibit 53.01.

830. No parties raised any issues with respect to these forecasts.

Commission findings

831. The forecast for total ES&G costs in the test period may be impacted by other directions included in this decision, as will the resulting ES&G rate. The Commission directs ATCO Electric, in the compliance filing, to update the total ES&G forecast costs and rates for 2013 and 2014, as necessary, to reflect all of the applicable directions included in this decision.

11.12 Allowance for funds used during construction

832. As explained at the beginning of this rate base section, AFUDC is calculated and applied to the balance of mid-year CWIP (adjusted for holdbacks) as well as mid-year materials and supplies inventory. This effectively increases the cost of any capital projects that are not completed before a fiscal year end. AFUDC is no longer applied to any mid-year CWIP balance for direct assigned capital projects; instead the mid-year CWIP balance for these projects is included in rate base. Details of the forecast mid-year CWIP for 2013 and 2014, as well as the resulting forecast AFUDC amounts based on the forecast weighted average cost of capital for 2013 and 2014, are included in Schedule 9-2 of the supporting revenue requirement schedules that were filed in conjunction with omissions and updates filing.[303] The forecast AFUDC amounts are $3.4 million for 2013 and $2.2 million for 2014.

833. No parties raised any issues with respect to these forecasts.

Commission findings

834. The forecast for total AFUDC costs in the test period may be impacted by other directions included in this decision, as will the resulting AFUDC rate. The Commission directs ATCO Electric, in the compliance filing, to update the total AFUDC forecast amounts and rates for 2013 and 2014, to reflect all of the applicable directions included in this decision.

11.13 Contributions in aid of construction

835. The contributions in aid of construction (CIAC) forecast was developed based on customer contribution decisions from the AESO or, where such decisions are not yet available, the contribution was calculated based on the AESO's construction contribution policy. ATCO Electric used the currently approved maximum investment levels in developing the forecast and requested that variances between actual and forecast contribution amounts, including changes to contributions resulting from implementation of the AESO's Rider I, be included in its direct assigned capital projects deferral account. The forecast for CIAC is $70.3 million for 2013 and $105.0 million for 2014.[304] As well, ATCO Electric provided its 2014 forecast contribution for Project 55725, in Schedule 10-8 of its omissions and updates filing.

Discussion of issues

836. The RPG expressed a concern that ATCO Electric may be under-reporting the forecast for CIAC. It submitted a list of projects for which it suggested a contribution was appropriate, but for which no contribution was forecast in the application. It suggested that ATCO Electric should provide some basic load characteristics and investment level calculations to demonstrate that the CIAC amounts are reasonable for each project.

[303] Exhibit 188.02.
[304] Exhibit 188.02, Schedule 10-8.

837. ATCO Electric explained in its rebuttal evidence that in accordance with the AESO's proposed policy effective July 1, 2011, capital expenditures are recorded up to ATCO Electric's approved investment level, at which point any additional capital expenditures are then offset by customer contributions. The result of the application of this policy is that customer contributions are recorded near the end of their related projects, which is why there are no forecast CIAC for certain projects. It also provided some basic load information as well as customer contribution decision references, and an updated CIAC forecast for its direct assigned capital projects. The forecast CIAC amounts for 2013 and 2014 for the direct assigned capital projects, included in the rebuttal evidence, were reflected in the supporting revenue requirement schedules that were filed in conjunction with the omissions and updates filing.

838. The RPG did not consider ATCO Electric's CIAC forecast update to be sufficient, and indicated that there were some projects for which the CIAC amounts were reduced, even though the capital cost forecast for these projects was increased. It reiterated its recommendation that ATCO Electric be directed to provide sufficient and adequate information to support its forecast.

839. The RPG also identified a concern with the policy of ATCO Electric to record CIAC near the end of the related projects. The effect of doing so understates contributions and results in an overstatement of revenue requirement. It referred to the provisions of Section 5 of the ISO tariff and it recommended that ATCO Electric be directed to provide necessary and sufficient information to justify its policy about recording CIAC, when customers are compelled to provide contributions in advance of ATCO Electric's expenditures, and to modify the policy if it cannot be justified.

Commission findings

840. In response to the RPG's request that some basic load characteristics should be provided by ATCO Electric, the Commission finds that ATCO Electric has provided such information. The Commission expects that ATCO Electric will continue to do so for future GTAs and does not consider it necessary to make a direction to this effect.

841. ATCO Electric has stated that its CIAC forecast was developed based on decisions from the AESO, or in the absence of such, on the AESO's customer contribution policy. ATCO Electric has also explained that the absence of forecast contributions for some projects which, by their nature, would appear to require a contribution, is the result of its internal policy to record contributions toward the end of the project.

842. For regulatory purposes, a customer contribution is to be accounted for as soon as it is confirmed that a contribution will be required for the project. Waiting until capital expenditures reach ATCO Electric's approved investment level before contributions are received effectively overstates the rate base, and does not recognize the obligation for a customer contribution. This would be especially troublesome if a customer has already paid the contribution up front, ATCO Electric has incurred capital expenditures, and a number of years have passed before the contribution is recorded as a reduction to rate base, especially during this time when the return on CWIP for direct assigned capital projects is included in revenue requirement.

843. The Commission directs ATCO Electric, in the compliance filing, to include in its forecast for contributions, the amounts that were included in Schedule 10-8 of the supplementary revenue requirement schedules filed in conjunction with the omissions and updates filing, adjusted for any other directions in this decision that may impact these amounts, and the

contributions for any projects where, based on the nature of the project, a contribution will be required. The Commission further directs ATCO Electric to provide, in the compliance filing, a detailed listing of each project for which, based on the nature of the project, a contribution will be required, how the required contribution amount was calculated, whether the contribution has been received by ATCO Electric, and when any contribution that has been received was paid to ATCO Electric by the customer(s).

844. The Commission finds that ATCO Electric's request that variances between actual and forecast contribution amounts be included in its direct assigned capital projects deferral account is acceptable, especially considering that this has been the practice in the past, and that the Commission approved the continuation of the direct assigned capital projects deferral account for 2013 and 2014 in Section 5.1.4 of this decision. However, the Commission finds that this approval is only for the contributions for the direct assigned capital projects, and not for any contributions with respect to non-direct assigned capital projects, because ATCO Electric will take the risk for the contribution forecast for the non-direct assigned capital projects, just as it takes the forecast risk for the capital expenditures and additions for the non-direct assigned capital projects. In addition, this does not include approval to include in the calculation of the direct assigned capital projects deferral account for either of 2013 and 2014, any contributions with respect to implementation of the AESO's Rider I. The process to address any contributions with respect to the AESO's Rider I in 2013 and 2014 is set out in Section 5.1.7 of this decision.

845. Last, the contributions forecast includes an amount of $8.6 million in 2014 for Project 50200, transmission arc proofing. Considering that there are no forecast expenditures or additions for this project in either of 2012, 2013 or 2014, the Commission directs ATCO Electric, as part of the compliance filing, to explain why a contribution for this project is forecast in 2014.

11.14 Retirements and adjustments for PP&E

846. In response to information request AUC-AE-024,[305] ATCO Electric described the process it uses to ensure that asset retirements are recorded in a timely fashion, and it indicated that it has processed an average of 4,600 retirement transactions per year over the past three years. In the same response, it included a copy of its policy that describes the accounting treatment involved in the retirement of PP&E when it has been replaced and/or removed from service, sold, decommissioned or destroyed due to accident. It also identified a mathematical error made with respect to the accumulated depreciation aspect of the forecast amounts for 2013 and 2014. The latest forecast amounts for retirements and adjustments, including the accumulated depreciation aspects, are included in the supporting revenue requirement schedules that were filed in conjunction with the omissions and updates filing.[306]

847. ATCO Electric forecast retirements of $7.4 million in 2013 and $7.5 million in 2014,[307] with accumulated depreciation adjustments of $8.4 million in 2013 and $8.5 million in 2014.[308]

848. No objections were raised about the forecast amounts by any of the interveners.

[305] Exhibit 50.01.
[306] Exhibit 188.02, Schedule 10-2, lines 10-13; Schedule 10-3, lines 10-13.
[307] Exhibit 188.02, Schedule 10-2, sum of lines 11, 12 and 13.
[308] Exhibit 188.02, Schedule 10-3, sum of lines 11, 12 and 13.

Commission findings

849. The actual retirements were $10.0 million in 2010, $2.2 million in 2011, and the latest 2012 forecast amount is $7.7 million. This variation between the years demonstrates the variability in this area, and suggests that arriving at an accurate forecast is difficult. The 2013 and 2014 amounts are at a level that is consistent with the 2012 forecast. Accordingly, the Commission approves the forecast retirements as filed.

850. The actual accumulated depreciation adjustments were $13.6 million in 2010, $5.3 million in 2011, and the 2012 latest forecast amount is $9.1 million. This variation between the years demonstrates the variability in this area, and suggests that arriving at an accurate forecast is difficult. The 2013 and 2014 amounts are at a level that is consistent with the 2012 forecast. Accordingly, the Commission approves the forecast accumulated depreciation adjustments as filed.

12 Necessary working capital

851. ATCO Electric submitted that it had completed a review of the components of each of the items in necessary working capital, to ensure that the nature of the revenues and expenses included in each category had not changed materially since the previous lead/lag study was completed and filed in the 2009-2010 GTA. Based on this review, ATCO Electric updated its net operating expense lag days from 28.6 to 28.0, mainly due to an increase in the operating expense lag. ATCO Electric's forecast of necessary working capital was $35.9 million for 2013 and $42.8 million for 2014,[309] and these amounts were added to its rate base.[310]

852. As detailed in Schedule 11-2 of the application, working capital is calculated in a number of areas, including cash operating expenses, income tax, inventory, long-term debt, preferred equity, common equity, and depreciation. In response to information request ADC-AE-017,[311] when asked to explain the rationale for including working capital related to depreciation and equity, ATCO Electric replied as follows:

> Consistent with past precedent established by the AUC and its predecessor, ATCO Electric assigns a zero expense lag to depreciation and the retained earnings component of common equity. The rationale for including these components in working capital is that depreciation and retained earnings are internally generated sources of funds used to finance plant additions. Although there is no certainty regarding the timing of the reinvestment, the assumption is made that the expenditures occur evenly throughout the year with a payment date equivalent to the service provision date. Therefore depreciation and common equity have been assigned a zero expense lag resulting in a net lag equivalent to the entire revenue lag.

[309] Exhibit 188.02, Schedule 11-1.
[310] As shown in Exhibit 188.02, Schedule 10-1, lines 16 and 23.
[311] Exhibit 52.01.

Discussion of the issue

853. The ADC took issue with the inclusion of the following components in working capital:

- depreciation expense
- common equity (retained earnings)
- common equity (dividend)

854. The ADC submitted that depreciation expense is a non-cash item and added that ATCO Electric does not pay depreciation expense to a vendor on a day-to-day basis in the provision of service to customers. It also submitted that equity returns represent the net earnings of the company, that ATCO Electric earns a return on the working capital component of rate base, and that by including a component for equity returns in working capital, it is requesting another layer of profit, in effect, a profit on profit. It also stated that equity returns are not day-to-day expenses paid by ATCO Electric to vendors in the provision of service to customers. The ADC's witness indicated that, in the other regulatory jurisdictions in the United States that he is familiar with, depreciation expense and equity returns are specifically excluded from working capital. The ADC also commented that recognizing depreciation and common equity for the long-term capital needs of ATCO Electric is unnecessary.

855. The ADC explained that, as a utility provides service to customers, it can incur expenses for delivering services that will have to be paid to third-party vendors before it recovers payment from customers for the services provided. The utility will need to keep an amount of cash working capital available to pay third-party vendors, until it receives payment from customers. Because earnings and depreciation expense are not items that require ATCO Electric to write a cheque to third-party vendors, they do not impact the amount of cash working capital that ATCO Electric needs to maintain for this temporary cash disbursement and receipt timing difference. The ADC recommended removing the three items listed in paragraph 853 above from necessary working capital.

856. ATCO Electric stated that its inclusion of depreciation and common equity in working capital is based on long standing regulatory practices approved by the Commission and its predecessors dating back to 1991. It added that the underlying factors that supported the previous approval of these practices continue to be applicable for purposes of this application, and it provided extracts from Decision E91095[312] and Decision U97065[313] in support of its position. ATCO Electric also added that the ADC raised the same issue in the AltaLink Management Ltd. 2011-2013 GTA and in Decision 2011-453 on that application, the Commission found in favour of AltaLink Management Ltd.

857. ATCO Electric submitted that it does not write a cheque to vendors for depreciation expense and common equity, but that depreciation expense and common equity components of working capital are used to finance plant additions, which the ADC ignored. ATCO Electric

[312] Decision E91095: The Public Utilities Board, Alberta: Alberta Power Limited, 1991 General Rate Application, File 910083 2050 0005 0002, December 13, 1991.
[313] Decision U97065: Alberta Energy and Utilities Board: 1996 Electric Tariff Applications, Files: APL 1105-1 / EPI 1700-1 / TAU 1204-1 / GRIDCO 1800-1, October 31, 1997.

further argued that the ADC has not provided any evidence of other Canadian jurisdictions where depreciation expense and common equity have been excluded from working capital calculations.

858. The ADC responded that it was aware of the Commission's findings on this issue in Decision 2011-453 and that it was requesting the Commission to reconsider its position in this regard.

Commission findings

859. The issue of including depreciation and common equity in working capital has been explored in previous applications decided upon by the Commission or its predecessor. In addition to Decision E91095 and Decision U97065, this issue was also addressed in Decision C90026.[314] There has to be compelling evidence which clearly demonstrates that these findings were in error, or new evidence that can be brought to bear that would support a change to the previous findings, before the Commission will revisit the decision it has previously made on this issue. The ADC has presented no such evidence in this proceeding.

860. Although the ADC's witness submitted that depreciation expense and equity returns are specifically excluded in regulatory jurisdictions in the United States, the witness did not provide details of whether this encompassed all regulatory jurisdictions in the United States, or the details regarding why the specific exclusions had been made. Consequently, the Commission has no basis to evaluate the circumstances regarding those exclusions and whether they are similar to the circumstances that exist for the Alberta utilities that are regulated by the Commission.

861. The ADC was unable to provide any direct evidence with respect to what other regulatory jurisdictions in Canada have done with respect to this issue, as evidenced by the ADC's response to information request AUC-ADC-004.[315] Such information would have been helpful in this case.

862. Pages 24 and 25 of Decision C90026 include a discussion on the payment lag with respect to equity returns. The issue under discussion was not about whether the equity returns are cash expenses but when the return on equity was due. There is also discussion about an argument put forward by an intervener group that, because a utility collects its allowed returns before year-end, reinvesting collections or enabling shareholders to reinvest through their dividends enables shareholders to earn compounded returns greater than the allowed return. In response to this argument, the Commission's predecessor found as follows:

> The Board agrees with CWNG's [Canadian Western Natural Gas Company Limited]argument that the actual compounding would be difficult to determine and would definitely be lower than that suggested by the FGA [Alberta Federation of Gas Co-ops and Gas Alberta]. Accordingly, the Board finds that it has no evidence available as to what the actual payment lag on returns should be and CWNG's payment lag of zero will be used for the purpose of this Decision.[316]

863. There is a substantial amount of discussion on this same issue included on pages 165 to 170 of Decision E91095, which ultimately led to the PUB deciding that it was not persuaded by the evidence presented by the interveners that compounding of returns on that

[314] Decision C90026: The Public Utilities Board, Alberta: Canadian Western Natural Gas Company Limited, Determine a rate base and fix a fair return for the years 1989, 1990 and 1991, File E4.7.35-89, July 27, 1990.
[315] Exhibit 107.01.
[316] Decision C90026, page 25.

portion of cash flow related to retained earnings would necessarily result in an increase in the effective rate of return on common equity.

864. The EUB also commented on the issue of compounding in Decision U97065, and once again rejected the recommendations made by the interveners to make adjustments in this regard. The EUB did direct, in that decision, that 50 per cent of the common equity return be treated the same as preferred equity return for purposes of working capital.

865. The issue of compounding, addressed previously on at least three occasions, is similar to the "profit on profit" argument raised by the ADC in this application. The ADC has not provided any new evidence on why the previous findings made on this issue should be reconsidered in the current proceeding. Therefore, the Commission finds that there is no basis upon which to accept the ADC's recommendation to exclude the retained earnings and return components from the calculation of necessary working capital.

866. The Commission has approved the inclusion of CWIP in rate base for direct assigned capital projects, which was not in place previously when the issue of depreciation being a source of financing for capital projects was discussed. However, no party raised this as a consideration during the course of the proceeding.

867. Similar to the issue of common equity, this issue of depreciation in necessary working capital was also raised and addressed in Decision C90026,[317] Decision E91095,[318] and Decision U97065.[319] In each of these cases, the regulator approved the inclusion of depreciation. The ADC has not provided any evidence on why the previous findings made on this issue should be reconsidered in the context of the facts in this proceeding. Therefore, there is no basis upon which to accept the ADC's recommendation to exclude the depreciation component from the calculation of necessary working capital.

868. On the basis of the above, the Commission finds that there is no justification to change the necessary working capital methodology at this time, and it consequently rejects the ADC's request to exclude the depreciation, retained earnings, and dividend components from the calculation of ATCO Electric's necessary working capital for the years 2013 and 2014.

869. In the response to a Commission question on the undertaking responses provided by ATCO Electric,[320] ATCO Electric identified an error with respect to the income tax amounts included in the necessary working capital schedule. In the supporting revenue requirement schedules[321] filed in conjunction with the omissions and updates filing, for each of the years 2011 to 2014, the income tax amounts included in Schedule 11-2 include the federal FIT. When questioned about this, ATCO Electric clarified that the income tax amount in Schedule 11-2 should only include the current income taxes and the "other items," and added that it would incorporate this update in the compliance filing. The Commission therefore directs ATCO Electric, in the compliance filing, to remove any FIT amounts for the years 2011, 2012, 2013 and 2014, when calculating the income tax amounts to be included on the necessary working capital schedule for these years.

[317] Decision C90026, pages 26-27.
[318] Decision E91095, pages 163-165.
[319] Decision U97065, pages 310-315.
[320] Exhibit 226.01, response to AUC-AE-004.
[321] Exhibit 188.02.

870. The Commission is also aware of a typing error in Schedule 11-3 included as part of the supporting revenue requirement schedules[322] filed in conjunction with the omissions and updates filing. The test period years identified on that schedule are "2011" and "2012." In response to information request AUC-AE-026,[323] ATCO Electric confirmed that these should read "2013" and "2014." For the sake of accuracy and completeness, the Commission directs ATCO Electric, in the compliance filing, to update Schedule 11-3 that will be submitted as part of the supporting revenue requirement schedules, to include the correct test year labels.

13 Allocation of costs

871. The transmission function's revenue requirement includes a number of categories of costs that are forecast on a company-wide level and then allocated between the transmission function and the distribution function, using a number of different methodologies. These categories of costs, which also include costs for certain capital projects, are forecast on a company-wide level because they cannot be directly assigned to either the transmission function or the distribution function. ATCO Electric provided details of this cost functionalization in Section 27 of the application.

872. General O&M expenditures comprise expenditures for communication equipment, maintenance of company-owned houses and maintenance of offices, warehouses and yards. The various methodologies used by ATCO Electric to allocate these costs are listed in Schedule 27-1 of the application and are described in more detail in paragraphs 340-342[324] of the application. ATCO Electric added that, as a result of updating the assignment percentages, there has been a $0.4 million increase in the costs allocated to the transmission function in 2013, and a corresponding decrease in the costs allocated to the distribution function. The impact in 2014 is an increase to transmission of $0.5 million and a corresponding decrease to distribution.

873. Common operations consist of a number of functional areas, as included in Schedule 27-4 of the application. ATCO Electric also uses various methodologies to allocate the costs for these areas, as listed in Schedule 27-4 of the application and described in more detail in paragraph 354[325] of the application. ATCO Electric added that, as a result of updating the assignment percentages, there has been a $0.6 million increase in the costs allocated to the transmission function in 2013, and a corresponding decrease in the costs allocated to the distribution function. The impact in 2014 is an increase to transmission of $0.7 million and a corresponding decrease to distribution.

874. Corporate A&G expenses are those corporate costs that are not directly associated with the principal activities of the company. The methodologies used by ATCO Electric to allocate these costs are listed in Schedule 27-2 of the application and are described in more detail in paragraphs 346 to 347[326] of the application. ATCO Electric added that, as a result of updating the assignment percentages, there has been a $1.9 million increase in the costs allocated to the transmission function in 2013, and a corresponding decrease in the costs allocated to the

[322] Exhibit 188.02.
[323] Exhibit 50.01.
[324] Exhibit 1, application, Section 27.
[325] Exhibit 1, application, Section 27.
[326] Exhibit 1, application, Section 27.

distribution function. The impact in 2014 is also an increase to transmission of $1.9 million and a corresponding decrease to distribution.

875. ATCO Electric included information in paragraph 357[327] of the application regarding the allocation methodologies for those general taxes other than income taxes that cannot be directly assigned.

876. Corporate general PP&E expenditures comprise expenditures for office furniture, tools and instruments, and equipment and leasehold improvements. Corporate computer systems expenditures are related to expenditures on corporate computer systems such as human resources systems and financial information systems. The methodologies used by ATCO Electric to allocate these costs are listed in Schedule 27-3 of the application and are described in more detail in paragraph 350[328] of the application. ATCO Electric added that, as a result of updating the assignment percentages, there has been a $0.4 million increase in the costs allocated to the transmission function in 2013, and a corresponding decrease in the costs allocated to the distribution function. The impact in 2014 is an increase to transmission of $0.1 million and a corresponding decrease to distribution.

Discussion of the issues

13.1 Allocation updates

877. The ADC raised an issue regarding the overall allocation update between ATCO Electric's transmission and distribution functions. In previous GTAs, when the revenue requirements for the transmission and distribution functions were applied for in the course of the same application, any cost increases for one function as a result of allocation updates were reflected as cost decreases in the other function. Consequently, ATCO Electric as a whole only recovered the approved amount of the total cost. In the current 2013-2014 GTA, because there is no distribution function revenue requirement application, it is not possible to verify that the cost increases for transmission identified by ATCO Electric as a result of allocation updates, have been reflected as cost decreases in the distribution function.

878. The ADC submitted that, if the allocation updates for the transmission function proposed by ATCO Electric for the 2013 to 2014 test period are not updated in the distribution function, ATCO Electric, as a company, will recover more than the total approved cost for these areas. The ADC included an example of how this would be manifested.[329] It indicated that it is necessary for ATCO Electric to demonstrate that these allocation updates have been adjusted in its distribution function and, until this is done, the allocation updates proposed by ATCO Electric in the current GTA should be denied. It also stated that this will reduce the transmission revenue requirement by $2.9 million in 2013 and $3.0 million in 2014.

879. The ADC submitted that ATCO Electric has not yet reflected the allocation updates in its distribution function's rates, that this proposed allocation update should be considered by the Commission within the distribution function's annual rate proceeding, and it recommended that the distribution function's rates be lowered to reflect the impact of the allocation updates.

[327] Exhibit 1, application, Section 27.
[328] Exhibit 1, application, Section 27.
[329] Exhibit 88.02, ADC evidence, page 8.

880. ATCO Electric submitted that, for each of corporate A&G costs, common operations costs, and general O&M costs, the amount forecast to be allocated to the distribution function for 2013 exceeds the amount approved for the distribution function for 2012 in the 2011-2012 GTA. It submitted that, after factoring in the approved "I-X" factor of 1.71 per cent under PBR for 2013, there are forecasted revenue deficiencies for the distribution function in 2013 of $0.7 million for common operations, $2.4 million for general O&M costs, and $0.8 million for corporate A&G. ATCO Electric added that this is a total deficiency of $3.9 million for 2013, and that the use of the updated cost allocators are not resulting in a situation where it will collect more in combined rates than it has actually incurred in transmission and distribution expenses.

881. ATCO Electric indicated that it has been allocating costs between its distribution and transmission functions for an extended period of time, and that the allocation methodology and approach have been consistently approved by the Commission. It added that the exact same allocation methodology used in the last GTA, and for many years before, is used in this proceeding. It submitted that the allocation percentages approved in the 2011-2012 GTA reflect information from 2008 to 2009 and, in the current application, this information is being updated to reflect actual information available from 2011 and, where applicable, 2010. It also indicated that both the distribution and transmission functions have experienced significant growth in recent years and are forecast to do so in 2013 and 2014. It added that, although this has also caused the overall quantum of common costs to increase, the transmission function has grown at a faster rate than the distribution function.

882. ATCO Electric argued that it would be entirely inappropriate to ignore the updated allocation input information from 2010 and 2011, and instead base the allocations on the data from the previous GTA. It stated that the real issue in this proceeding is whether the methodology it employed, and the information it relied upon in implementing that methodology, represents a reasonable and reliable basis upon which to allocate common costs to the transmission function.

Commission findings

883. ATCO Electric has not explained why a small portion of the costs included in Schedule 22-1 of the application[330] (isolated generation operating costs) is allocated to the distribution function, or the basis of the allocation. The Commission directs ATCO Electric, in the compliance filing, to explain why some costs included in Schedule 22-1 of the application are allocated to the distribution function, and to explain the basis for the allocation.

884. One of the cost allocation methodologies uses the average of the percentages for revenue, net PP&E, and capital expenditures (revenue, PP&E and capital expenditures methodology). It is included in schedules 27-1, 27-2, 27-3 and 27-4 of the application. ATCO Electric added that it used 2011 actuals as the inputs in the calculation of this revenue, PP&E and capital expenditures methodology, for the purposes of allocating costs for 2013 and 2014. In Decision 2013-111, the Commission directed that the revenue, PP&E and capital expenditures methodology be revised in order to allocate the ATCO Ltd. group of costs to the ATCO Utilities. The Commission considers that, for consistency and for the same reasons it directed the changes to the revenue,

[330] Schedule 22-1 submitted with Exhibit 188.02 (the supporting revenue requirement schedules filed in conjunction with the omissions and updates filing) shows the same forecast allocated amounts for 2013 and 2014 as those filed in Schedule 22-1 of the application.

PP&E and capital expenditures methodology in Decision 2013-111,[331] the same changes should be made to the revenue, PP&E and capital expenditures methodology in this decision. The Commission directs that the use of the 2011 actuals as inputs in the calculation of the revised methodology is applicable, because these represent information from two years prior to the first test period. The Commission commented on this in paragraph 134 of Decision 2013-111.

885. With regard to any amounts included in the application for 2013 and 2014 that were allocated using the revenue, PP&E and capital expenditures methodology, the Commission consequently directs ATCO Electric, in the compliance filing, to update these amounts to reflect the following changes it is directing to the revenue, PP&E and capital expenditures methodology:

- Capital expenditures must be removed from the allocation methodology.
- Labour expense must be incorporated into the allocation methodology.
- Gross revenue must be removed from the allocation methodology and replaced with revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation.

886. The Commission further directs that the resulting revenue figures be given an equal weighting in the formula, along with labour expense and total assets.

887. ATCO Electric has historically applied a consistent methodology of allocating costs to its transmission and distribution functions. The ADC proposes that if the same process is followed this year, the transmission function will get an increase in its allocated share of costs. Because the distribution function will not participate in this allocation update, the ADC expects that ATCO Electric as a company will recover more than the approved costs for these areas, as the distribution function's cost base will not be correspondingly decreased. The ADC recommended that the distribution rates be lowered to reflect the impact of the new allocation updates. The Commission agrees with ATCO Electric that the real issue here is whether the methodology employed by ATCO Electric represents a reasonable and reliable basis upon which to allocate common costs to the transmission function. The Commission does not find that the methodology is unreasonable for allocating these costs to the transmission function.

888. The important question to consider is how the advent of PBR for ATCO Electric's distribution function, and the resulting fact that combined transmission and distribution revenue requirement applications are no longer submitted, impact the recovery of common costs for both the transmission and distribution functions. The Commission agrees with ATCO Electric that the ADC's recommendation to reflect the allocation updates in the next distribution annual rates proceeding is not practical, because there is no mechanism in the PBR for such updates. This reflects the breaking of the link between costs and revenues during the PBR term, as described in paragraph 16 of Decision 2012-237.

13.2 Allocation of corporate administration and general costs

889. Mr. Bell submitted evidence on behalf of the UCA, also with regard to the allocation of "common back office costs," particularly in light of the fact that the distribution function is under

[331] Decision 2013-111, paragraphs 126-135.

a PBR regime starting in 2013. Mr. Bell added that the implementation of a PBR regime for the distribution function creates an opportunity to "save" distribution costs, merely by allocating them to the transmission function, to the benefit of shareholders. The Commission has addressed this concern in Section 13.1 of this decision.

890. Mr. Bell also submitted that the allocation methodology with respect to the allocation of corporate A&G costs should be redesigned, to recognize that ATCO Electric has created an entire parallel organization structure for its capital projects division, including a separate president, a separate vice-president and controller, and other positions that provide back office functions for the capital projects division. He submitted that, at a minimum, the allocation ratios for corporate A&G approved in the 2011-2012 GTA should be maintained in 2013 and 2014.

891. Mr. Bell indicated that, while total corporate A&G costs are forecast to decline by $1.3 million from 2012 to 2013, the amount of corporate A&G costs forecast to be allocated to the distribution function declines by $5.9 million, and the amount of corporate A&G costs forecast to be allocated to the transmission function increases by $4.6 million.[332] He indicated that the transmission function already includes a capital projects division, the costs of which are charged entirely to the transmission function and stated that, because the capital projects division provides many of the "back office services," the increase in the allocation of corporate A&G costs to the transmission function is a concern.

892. Mr. Bell indicated that, although the majority of the costs relating to the capital projects division are charged to capital, many of those costs would be charged to corporate A&G if they were not directly attributable to the capital program. Mr. Bell added that, because of this, to continue with the historic methodology of allocating corporate A&G costs is not appropriate. He advised that the total corporate A&G costs approved in 2012 were $52.5 million, of which $21.5 million (or 41.0 per cent) was allocated to the transmission function, and $31.0 million (or 59.0 per cent) was allocated to the distribution function. Mr. Bell advocated that at a minimum, the 41:59 ratio be used to allocate the 2013 and 2014 total corporate A&G costs. He stated that ideally the methodology be modified to recognize the services provided internally by the capital projects division, and provided some possible modifications.

893. During the interrogatory process, the Commission requested that Mr. Bell provide an example of the modifications to the corporate A&G cost allocation methodology that would be required in order to recognize the services provided internally by the capital projects division. He provided such an example in his response to information request AUC-UCA-004.[333]

894. ATCO Electric submitted that it is using the same allocation methodology that has been tested and approved by the Commission in GTAs since the mid-2000s. It added that, in this current application, it has updated the historically approved common cost studies that are used as inputs into cost allocation methodologies, and has applied the resulting allocation percentages to the total common costs.

895. ATCO Electric indicated that one of the reasons the total corporate A&G costs are forecast to be lower in 2013 and 2014 than they were in 2012, is that the 2013 and 2014 forecast for total corporate A&G costs does not include any forecast amounts for the distribution portion of the rate case provision and the reserve for injuries and damages, and it submitted that when

[332] These figures are based on the information included in Schedule 25-1 of Exhibit 1, application, Section 25.
[333] Exhibit 109.03.

this is factored in, the amounts allocated to the distribution function in 2013 and 2014 are greater than the amount allocated in 2012.

896. The UCA argued that the same allocation methodology in use by ATCO Electric was developed prior to the creation of separate capital and operating divisions for ATCO Electric's transmission function, and without recognition of these changes in its structure. Mr. Bell's concern about the methodology "double dipping" is not addressed. The UCA submitted that Mr. Bell's methodology should be used to allocate the 2013 and 2014 total corporate A&G costs, and at a minimum, the corporate A&G costs allocated to transmission should be adjusted downward by $5.4 million in 2013 and $5.8 million in 2014. The UCA also recommended that the Commission direct ATCO Electric to implement the allocation methodology recommended by Mr. Bell in future applications.

897. ATCO Electric stated that the UCA's analysis assumes that there is some form of duplication of the services provided by the capital projects division and the corporate A&G functions, and that it had presented detailed evidence to demonstrate that there is no duplication of the services.

898. The UCA countered that this does not address Mr. Bell's explanation of how the historical allocation methodology is distorted by capitalizing back office costs undertaken by the new capital projects division of the transmission function. The UCA added that Mr. Bell's evidence demonstrated that ATCO Electric's historic cost allocation methodology should not be used following its restructuring, because it double counts back office costs. The UCA added that the allocation formula's identification and allocation of costs between transmission and distribution, over-allocates on the transmission side by not taking into account the back office costs that the capital division capitalizes.

Commission findings

899. The whole purpose of Mr. Bell's request in this area was summarized by him while he was being questioned by Commission counsel at the hearing. That summary is as follows:

> A. Well, yeah, as I said, when the allocation methodology was developed and implemented, all of these back office functions were included in one central area and allocated between transmission and distribution. ATCO Electric has now chosen to create a separate infrastructure to manage its capital projects better. Along with that, some of the functionality that would have been in the common function has to have moved out with the resources that have moved, and so there needs to be recognition of that revised structure in allocating the common costs.[334]

900. Mr. Bell has provided no evidence that any of the functionality that would have been in the corporate A&G area has "moved out" with the resources that have moved to transmission. His statement that some of the functionality "has to have moved out" is not supported by anything on the record of this proceeding. ATCO Electric has, however, provided sufficient

[334] Transcript, Volume 7, page 1463, lines 18-25; page 1464, lines 1-3.

evidence, including the material provided in the response to information request UCA-AE-012,[335] that there is no duplication of "back office functions" between the capital projects division and the corporate A&G functions.

901. The UCA did not request a reduction to the total overall corporate A&G costs; if the UCA had a concern about the duplication of services it would have made a recommendation to reduce the overall level of total corporate A&G costs, instead of recommending that the transmission function be allocated a smaller portion of the total corporate A&G costs. The UCA's recommendation simply allocates less of the total corporate A&G costs to the transmission function, while any "duplicated services" costs still remain in the overall level of costs. The Commission agrees with Mr. Bell that if the costs of the capital projects division are not charged to capital, they would be charged to corporate A&G. However, the fact that the majority of the costs of the capital projects division are charged to capital demonstrates that they are not included in corporate A&G costs, and therefore are not duplicated.

902. Mr. Bell refers to "common back office costs" and "back office functions" and argues that the capital project division now undertakes these "back office functions" for the transmission function. Mr. Bell suggests that, because of this, the transmission function's share of the remaining "back office functions" left in the corporate A&G area should be reduced. If this were the case, the capital projects division would not be able to charge the costs for performing such "back office functions" to capital, as these types of costs are not permitted to be capitalized. In response to information response UCA-AE-012(b),[336] ATCO Electric identified certain capital projects division costs that are not capitalized, with the largest of these being right-of-way payments. These payments, also known as annual structure payments, are included in direct O&M, and are therefore not considered corporate A&G costs.

903. The fact that the majority of the capital projects division costs are charged to capital, demonstrates that there are no "back office costs" included in this division's costs. This results in all back office costs being included in the corporate A&G area. If it were possible to capitalize all "back office function" costs, there would be no corporate A&G area costs at all. Mr. Bell expressed a concern that the historical allocation methodology is distorted by capitalizing the back office costs undertaken by the new capital projects division. The Commission finds, through its analysis, that these historical "back office costs" are not included in the costs of the capital projects division, and are therefore not capitalized by that division. Further, regardless of where "back office costs" are incurred, they are simply by their nature not eligible to be capitalized. ATCO Electric has left these costs as corporate A&G costs that need to be allocated.

904. Because the Commission has found that the "back office costs" are still entirely in the corporate A&G costs, and have not been capitalized by the transmission function, it also finds that the historical allocation methodology for corporate A&G costs has not been distorted and therefore it does not need to be revised as suggested by Mr. Bell. The "back office costs" are not double counted because there are none in the capital projects division's costs. Therefore, the Commission rejects the request by the UCA that Mr. Bell's methodology be used to allocate the corporate A&G costs for 2013 and 2014, and it also rejects the UCA's request that Mr. Bell's allocation methodology be used to allocate corporate A&G costs in future ATCO Electric transmission applications.

[335] Exhibit 51.01.
[336] Exhibit 51.01.

14 Financing and credit metrics

905. ATCO Electric satisfies its financing requirements with a combination of internally and externally generated funds. External financing for ATCO Electric and its sister company, ATCO Gas and Pipelines Ltd., is obtained through CU Inc., which is ATCO Electric's parent company. ATCO Electric submitted that using CU Inc. as its financing vehicle results in more optimal sizing of public financings and minimizes the costs of market access. External financing is also more frequent, which enhances liquidity and minimizes variances from capital structure targets. CU Inc. is able to offer investors a lower risk investment through diversification between gas and electric utility operations, and this reduced risk to investors results in stronger credit ratings.

906. In ATCO Electric's 2011-2012 GTA, in order to address the potential negative impacts to its credit metrics arising from the company's robust capital program and significant amount of CWIP forecasted in 2011 and 2012, ATCO Electric applied for, and received approval for, the recovery of its transmission federal FIT, along with the inclusion of its transmission direct assigned capital projects CWIP in rate base.

907. ATCO Electric stated that it is forecasting in the 2013-2014 test period, a continued robust capital program, and added that it needs to ensure that its and ultimately CU Inc.'s credit metrics remain well supported during the test period. It indicated that credit metrics, along with other factors, are used by credit rating agencies to assess a company's overall credit rating. ATCO Electric advised that the stand alone credit metrics for the transmission function of the company are forecast to be under continued pressure during the test period. To help address this downward pressure on credit metrics, ATCO Electric applied to recover its provincial FIT, its federal FIT and CWIP in rate base.

14.1 Amount and timing of forecast debt issues

908. In its application, ATCO Electric forecast new debt issues of $794.5 million in 2012 (to be made subsequent to the June 29, 2012, date of the application), $826.0 million in 2013, and $625.1 million in 2014. Each of the debt issues was forecast to have a 30-year maturity date. ATCO Electric did not provide any update to the forecast debt amounts and maturity dates as part of the omissions and updates filing. ATCO Electric indicated that the forecast debt issues in 2013 and 2014 are planned to be issued to CU Inc., and will mirror the specific terms and conditions of public financing completed by CU Inc.

909. During the oral hearing, the CCA questioned the ATCO Electric witnesses about whether ATCO Electric had explored the possibility of obtaining Federal government loan guarantees for its transmission capital projects. The CCA submitted that ATCO Electric should finance its capital program at the lowest possible debt rates and in the best interests of its customers, and suggested that ATCO Electric should keep all of its options open with respect to how it obtains financing.

910. ATCO Electric stated that even if government-backed debt were available, it would not materially reduce CU Inc.'s cost of debt. It added that the TFCMC's Transmission Cost Recovery Subcommittee (TCRS), examined utilizing the provincial government's favorable credit rating to reduce financing costs for transmission projects, and concluded that it made little difference in terms of rate impact on customers. ATCO Electric submitted that it is undertaking

reasonable and appropriate steps to ensure that it finances its significant capital program at the lowest possible debt rates and in the best interests of both customers and the utility.

Commission findings

911. ATCO Electric operates under a deemed common equity ratio and has a relatively small amount of preferred shares. Debt is the residual of the capital structure. As a result, in order to maintain the actual ratios near the deemed levels, the amount of new debt issued is largely determined by the approved growth in rate base. The Commission directs ATCO Electric, in the compliance filing, to update the "Schedule of Debt Capital Employed and Embedded Cost" to include the actual debt issues for 2012. The Commission also directs ATCO Electric, in the compliance filing, to recalculate the amounts of new debt issues for 2013 and 2014 based on the approved growth in rate base for 2013 and 2014, and to reflect these amounts on the "Schedule of Debt Capital Employed and Embedded Cost." The Commission further directs that the forecast debt issues for 2013 and 2014 included in the compliance filing assume 30-year maturity dates.

912. The Commission considers that part of the prudent management of the debt costs includes exploring and obtaining any sort of assistance that results in a reduction to debenture rates. Even a small reduction in debt rates, when applied to a large debt amount over a long period of time, can result in significant savings in interest costs. The federal government has provided loan guarantees for certain transmission projects in eastern Canada, and the Commission finds that ATCO Electric should investigate the possibility of obtaining federal and provincial government loan guarantees and assessing the impact on debt costs. The Commission directs ATCO Electric, in its next GTA, to provide details about its efforts to obtain federal and provincial government loan guarantees, and the assessment of any such guarantees.

14.2 Amount and timing of forecast equity issues

913. In its application, ATCO Electric forecast new equity issues to its parent company of $451.0 million in 2012, $357.0 million in 2013, and $181.0 million in 2014. No new preferred share issues were forecast. ATCO Electric did not provide any update to the forecast equity share issues as part of the omissions and updates filing. As detailed on the "Continuity Schedule of Equity" included in the application,[337] ATCO Electric forecast share issues, rather than dividends, in each of the years 2012 to 2014.

Commission findings

914. ATCO Electric operates under a deemed common equity ratio. As a result, in order to maintain the actual equity ratios near the deemed level, the amount of new equity issued (net of any dividends) is largely determined by the approved growth in rate base. The Commission directs ATCO Electric, in the compliance filing, to update the Continuity Schedule of Equity to include the actual equity issues for 2012, to recalculate the amounts of equity issues for 2013 and 2014 based on the approved growth in rate base for 2013 and 2014, and to reflect these amounts on the "Continuity Schedule of Equity."

[337] Schedule 28-4.

14.3 Potential deferral account treatment for forecast debenture rates

915. ATCO Electric's witnesses were questioned on whether they believed a deferral account for debt rates was appropriate.[338] ATCO Electric submitted that its forecast debt rates were based on independent third party analysis from a number of sources and was therefore clearly capable of being forecast, and stated that its debt and preferred share forecasts should be approved as filed, without deferral account treatment.

916. The ATCO Electric witnesses were also questioned on the possibility of a deferral account for forecast debenture rates. When asked whether ATCO Electric would be in favour of a deferral account if the Commission reduced the forecast debt rates from 4.30 per cent for 2013 and five per cent for 2014, as forecast by ATCO Electric, to the 3.82 per cent for 2012 that was included in the omissions and updates filing, an ATCO Electric witness advised that under those circumstances ATCO Electric would be in favour of a deferral account.[339] In its argument, ATCO Electric explained that keeping debt rates at the 2012 levels would not provide it with an opportunity to recover its reasonably incurred costs, because the forecast information available to ATCO Electric indicated that the debt rates will go up during the 2013-2014 test period.

917. The CCA submitted that, based on the testimony of the ATCO Electric witness panel, there is greater certainty over long Canada bond rates in the current test period; and based on the CCA's recommendations that the 2013 debenture rate be set at 4.275 per cent and the 2014 debenture rate be set at 4.775 per cent, there is no need for a debt cost deferral account for the test years.

918. The ADC submitted that current interest rates are much lower than ATCO Electric's current embedded cost of debt and the forecasted interest rates for 2013 and 2014 included by ATCO Electric in its application, and this decline in capital market costs is not reflected in ATCO Electric's forecast. It stated that ATCO Electric's effort to eliminate a deferral account when it is in a position to benefit from declining debt costs, is self-serving and unjustified. The ADC argued that this is in stark contrast to when the deferrals were originally put in place, because then ATCO Electric was at significant risk of debt interest costs increasing above their embedded levels. It submitted that a deferral account should be implemented symmetrically to protect both shareholders and customers, and added that ATCO Electric's proposal to eliminate the debt cost deferral should be rejected.

919. ATCO Electric submitted that establishing a deferral account for the forecast debenture rates for debt issued in 2013 and 2014 does not meet the generally accepted criteria for a deferral account. It added that the imposition of a deferral account for a two year forecast period would result in inefficiencies and reduce the incentive to minimize costs.

Commission findings

920. The interest rate applicable to ATCO Electric's debt to be issued during a forecast period has not historically been subject to a deferral account. ATCO Electric has been at risk for forecast errors in this item during these test periods. In subsequent test periods, the actual interest rate has been used. This has provided ATCO Electric with a financial incentive to achieve the best interest rates that it can. Interest rates have been declining for several decades. Each year the additional decline in interest rates has been unanticipated by most forecasters. As interest rates

[338] Transcript, Volume 2, page 303, lines 13-25; page 304, lines 1-14.
[339] Transcript, Volume 3, page 577, lines 1-15.

declined, ATCO Electric has generally been able to issue debt at an interest rate lower than the forecast rate. In each of the years from 2009 to 2012 inclusive, ATCO Electric's actual rate for new debt has been lower than the approved rate.[340]

921. While the Commission agrees with ATCO Electric that interest rates are clearly able to be forecast, and are based on information obtained from third-party sources, the accuracy of those forecasts over the last number of years has been inaccurate. ATCO Electric has benefitted during the recent test periods from the difference between the actual interest rates and the approved forecast interest rates. ATCO Electric has no control over the general interest rates, which are dictated by market forces and government policy. This lack of control over an item has been used in the past to justify the establishing of a deferral account for the item in question.

922. In Schedule 28-2 of the supplementary revenue requirement schedules[341] that were filed in conjunction with the omissions and updates filing, ATCO Electric updated the 2012 forecast debenture rate to 3.82 per cent. Compared to the approved forecast debenture rate for 2012 of 6.35 per cent, this is a savings of approximately 2.5 per cent. Applying this 2.5 per cent to the approved debenture issue amount for 2012 of $747.8 million results in a savings to ATCO Electric of approximately $9.4 million pre-tax, using the mid-year basis. The Commission considers that such an amount is not insignificant and it demonstrates that the possibility of significant dollar variances with respect to debt costs exists. ATCO Electric is forecasting to issue over $800.0 million in debt in 2013 and over $600.0 million in 2014, which the Commission considers is quite material. Therefore, differences in interest rates could result in large variances in debt costs over the 2013-2014 test period.

923. To protect against possible interest rate forecast errors, and the possible material changes in debt costs that could result, the Commission finds that a deferral account for debenture rates should be established for the test period. This deferral account will protect not only customers but ATCO Electric as well.

924. The establishment of a deferral account for debenture rates normally would tend to reduce the incentive to minimize debenture costs, as ATCO Electric has submitted. This risk however, is mitigated by the nature of debt issuances by ATCO Electric via the historically agreed "mirroring down" of debt from CU Inc. The transmission and distribution functions of ATCO Electric, as well as the operations of ATCO Gas and Pipelines Ltd., all receive their financing through CU Inc. The distribution functions of ATCO Electric and ATCO Gas are currently being regulated under a PBR system. Under PBR, these operations are incented to obtain the lowest debenture rates, because any savings with respect to lower debenture rates are to the credit of the shareholders. By issuing all the debt for the parties on the same day, and allocating the debt based on each separate affiliate's needs, a common desire to achieve the least cost debt would be retained, and therefore the incentive to minimize debt costs is not lost with the deferral account.

925. The Commission directs ATCO Electric to establish a deferral account for debenture rates for the years 2013 and 2014.

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[340] As evidenced by Exhibit 50.01, Attachment 1 to the response to AUC-AE-31(a). This attachment shows the following: 2009 approved – 6.65 per cent, 2009 actual – 6.5 per cent and 6.2 per cent; 2010 approved – 6.65 per cent, 2010 actual – 4.95 per cent; 2011 approved – 5.75 per cent, 2011 actual – 4.54 per cent and 4.6 per cent; 2012 approved – 6.35 per cent, 2012 forecast – 4.65 per cent.

[341] Exhibit 188.02.

926. The calculation of the annual debenture rate deferral is to be calculated by updating the approved "Schedule of Debt Capital Employed and Embedded Cost" (Schedule 28-2) for 2013 to reflect the actual weighted debenture rate for 2013; and updating the same schedule for 2014 to reflect the actual weighted debenture rates for 2013 and 2014. The resulting embedded cost of debt for the applicable year is then to be used to update the "Schedule of Capital Structure and Average Cost of Capital" (Schedule 28-1) for that year, which will result in an updated return on long term debt for that year. The difference between the updated return on debt and the approved return on debt for that year is the resulting balance in the debenture rate deferral account for that year.

927. The Commission also directs ATCO Electric, in the compliance filing, to add the debenture rate deferral as well as the placeholders for the debenture rates for 2013 and 2014 to the updated Section 1, Attachment 3 schedule that will be submitted.

14.4 Forecast debenture rates

928. In its application, ATCO Electric initially forecast the interest rates for new debt issues at 5.10 per cent in 2013, and 5.85 per cent in 2014. This was subsequently reduced, based on the latest information in the omissions and updates filing, to 4.30 per cent and five per cent.[342] ATCO Electric's interest rate forecast was based on discussions with ATCO Ltd.'s treasury department and with financial institutions. In response to information request ADC-AE-107,[343] ATCO Electric provided extensive bank and consensus forecasts on which it had relied for the forecast in the application. In response to information requests AUC-AE-31[344] and CCA-AE-43,[345] ATCO Electric provided details regarding historical interest rates (forecast and actual), and historical spreads.

929. As part of its omissions and updates filing submitted on November 20, 2012, ATCO Electric advised that it updated its 2012 forecast debt rate to 3.82 per cent, based on actual debt issues that have occurred to date in 2012. Compared to the approved forecast debenture rate for 2012 of 6.35 per cent, this is a savings of approximately 2.5 per cent. ATCO Electric added that the update for the 2013 and 2014 rates was based on discussions with ATCO Ltd.'s treasury department, the same financial institutions that originally provided the information used to develop the forecasts in the application, as well as the October 2012 consensus forecast.

930. The CCA argued that, given the amount of borrowing during the test years, even a 10 basis point forecast error can mean more than a million dollars variance over the two-year test period. It stated that ATCO Electric's use of bank forecasts, in addition to the consensus forecast, lowered the debt rate by four basis points in 2013, but increased it by 16 basis points in 2014. The CCA submitted that ATCO Electric's use of bank forecasts introduced additional uncertainties and that only the consensus forecast should be used. This resulted in a forecast Canada 30-year bond rate of 2.79 per cent for 2013 and 3.29 per cent for 2014. The CCA added that ATCO Electric should use a bond spread of 148.5 basis points, and that this would result in a 2013 debenture rate forecast of 4.275 per cent, and a 4.775 per cent forecast for 2014.

[342] Exhibit 117.01, omissions and updates filing, page 6.
[343] Exhibit 52.01.
[344] Exhibit 50.01.
[345] Exhibit 53.01.

931. The CCA submitted that the consensus forecast reflects the consensus view of forecasters and already takes into account, and reflects, variance around a mean, and it argued that using bank forecast ranges in addition to the consensus forecast, serves to bring into the calculation another range of forecasts prepared by banks, whereas the consensus forecast has already considered various ranges of forecasts. It indicated that, if the consensus forecast is to be weighted together with bank forecasts, then all of the forecasts, on either side of the mean, that resulted in the single point consensus forecast must also be considered.

932. The CCA submitted that taking the mid-point of a wide forecast range obtained from the banks does not necessarily indicate that the correct number is being chosen, and added that ATCO Electric has not indicated when the bank forecasts were prepared, so it is not known whether they reflect the most current information. It argued that ATCO Electric's discussions with ATCO Ltd.'s treasury department personnel deserve little or no weight in view of the judgemental nature of how ATCO Electric's personnel may have interpreted those discussions.

933. ATCO Electric replied that although valuable to consider, the consensus forecast should not be the only data relied upon. Input from the banks (Bank of Montreal, the Royal Rank of Canada, Scotiabank and the Toronto Dominion bank) assists in developing a more complete, robust and accurate forecast. It advised that these are Canadian based banks with significant experience in forecasting debt rates, and argued that input from a number of sources, including personnel at ATCO Ltd.'s treasury department, is more reliable and reasonable than pure reliance on the consensus forecast. ATCO Electric indicated that the Canadian banks directly forecast long-term bond yields, whereas the consensus forecast only forecasts the 10-year yields, and as a result there is an imprecise adjustment used to arrive at the long-term forecast.

934. ATCO Electric also submitted that indicative credit spreads are not necessarily based on actual credit spreads observed on debt issued, but instead involve interpolations. Actual credit spreads may be different than indicative credit spreads. In 2011, when CU Inc. issued debt, its actual credit spread was seven basis points higher than the indicative level. ATCO Electric indicated that it may issue 40- to 50-year debt, which recently had spreads two to five basis points higher than 30-year debt.

Commission findings

935. For many years, the Commission has relied on the consensus forecasts in setting forecast debenture interest rates, although as stated above, those forecasts have been inaccurate. The consensus forecast provides a forecast of the interest rates on 10-year government of Canada debt. The consensus forecast is an average of the forecast of thirteen individual forecasters, which include the major banks in Canada as well as various other parties that provide forecasts.

936. From the information in paragraph 929 of this decision the Commission has observed that in the year 2012, the actual rate was 2.5 per cent below the approved forecast debenture rate, which is a significant variance. This large variance, and the large expected issuances of debt by ATCO Electric in 2013 and 2014, has resulted in the establishment of a deferral account for debenture rates. Typically, when a utility has a consistent bias in a forecast, the Commission must adjust those forecasts to a reasonable or justifiable level based upon the bias in those historical forecasts. With the establishment of a deferral account, ATCO Electric and ratepayers are both insulated from poor forecast results.

937. The Commission has taken notice of the Government of Canada benchmark bond yields on September 11, 2013, from http://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/, in setting placeholders for long-term debt rates for 2013 and 2014. This information is a readily accessible undisputed source representing the best estimate of long-term debenture rates. The Commission has found that in the absence of reliable and consistent forecasts, the best estimate of long-term debenture rates to use in setting placeholder rates in this proceeding are current rates near the time of the decision. Setting the placeholder at the current rate would minimize any expected difference in the deferral account settlement.

938. The government of Canada benchmark bond yield – 10-year yield on September 11, 2013, was 2.78 per cent, and the government of Canada benchmark bond yield – long-term was 3.26 per cent. The omissions and updates filing spread of 148.5 basis points over government of Canada bonds indicates that CU Inc. could issue long-term bonds at 4.745 per cent as at that date. This rate is above ATCO Electric's omissions and updates filing figure of 4.30 per cent, but below ATCO Electric's original 5.10 per cent forecast. The establishment of the deferral account will therefore protect ATCO Electric from the latest increase in rates, but could benefit ratepayers if rates return in 2014 to their 2012 issuance level. The Commission directs ATCO Electric, in the compliance filing, to use 4.745 per cent as the 2013 and 2014 placeholder for long-term debt.

939. The Commission acknowledges ATCO Electric's comments regarding indicative versus actual spreads when new debt is issued, but views the indicative spread on ATCO Electric's corporate debt as the best available estimate of the spread that would apply to a new issue.

14.5 Forecast preferred share rates

940. ATCO Electric has four series of preferred shares outstanding. The rate on one series was scheduled to reset in 2012, subsequent to the June 29, 2012, date of the application. Another series is subject to a rate reset in 2014. The rates on the remaining two series will not reset before the end of 2014 and are therefore known. ATCO Electric forecast that the rate reset levels would be 4.25 per cent for the 2012 reset and five per cent for the 2014 reset. ATCO Electric advised that the five per cent forecast was based on the five-year Canada bond rate and rate reset spreads, which were based on discussions with personnel at ATCO Ltd.'s treasury department and with personnel at financial institutions.

941. These forecasts were reduced in the omissions and updates filing. The actual reset yield of four per cent for 2012 was incorporated, and 4.80 per cent was forecast for the 2014 reset. ATCO Electric advised that the forecast for the 2014 rate was based on discussions with personnel at ATCO Ltd.'s treasury department and with personnel at financial institutions.

942. The CCA argued that ATCO Electric should use the consensus forecast for the five-year government of Canada bond rate, rather than considering the forecasts of banks and capital markets advisors. It concluded that the preferred share series that will reset in 2014 should have a forecast rate of 4.50 per cent. The CCA reiterated the same arguments in this area as it did with respect to the debenture rate forecasts. These arguments are described in paragraphs 930, 931 and 932 of this decision.

943. ATCO Electric submitted that the arguments it proffered with respect to debt rates were also applicable to preferred share rates. These arguments are summarized and described in paragraphs 933 and 934 of this decision.

Commission findings

944. The Commission must determine what the forecast will be for the rate reset for the year 2014.

945. The Commission accepts the update to the 2012 rate reset set out in the omissions and updates filing. Unlike the debenture rate forecast, which is applied to forecast debenture amounts of $826.0 million in 2013 and $625.0 million in 2014, the rate reset amount for the preferred shares will only be applied to $133.0 million, and only for the year 2014. The Commission therefore considers that any variances with respect to this forecast reset rate should not result in a material dollar amount. The difference between the 4.50 per cent recommended by the CCA and the 4.80 per cent forecast of ATCO Electric is 0.30. Applying the mid-year convention results in a difference of 0.15, and when this is applied to the $133.0 million the resulting impact on the revenue requirement for 2014 is approximately $0.2 million. The Commission finds that this is not a significant amount.

946. No evidence has been produced with respect to the historical forecasting accuracy of ATCO Electric with respect to dividend reset rates. There is evidence on the record[346] with respect to the forecasting accuracy of new preferred share issues. This information shows that the actual preferred share rate in 2009 was greater than the forecast, while the actual preferred share rate in 2010 was less than the forecast. The Commission considers that this is no evidence of a pattern of over forecasting, and finds that there is no reason to accept the CCA's recommended rate over the rate proposed by ATCO Electric. The Commission approves the forecast preferred share rate reset of 4.80 per cent for 2014 and directs ATCO Electric to use this rate in the compliance filing.

14.6 Credit facilities

947. ATCO Electric utilizes CU Inc. as the financing vehicle for its financing. In addition to the long-term debt financing, ATCO Electric also has access to CU Inc.'s credit facilities, along with Canadian Utilities Limited's credit facilities. ATCO Electric stated that these are necessary to ensure that its liquidity requirements are met and to provide flexibility in the timing and size for the issuance of long-term financing. They are also a backstop to the CU Inc. and Canadian Utilities Limited commercial paper program.

948. ATCO Electric submitted that in 2011, Canadian Utilities Limited and CU Inc. amended their credit facilities to extend the term, reflect current market pricing, and increase the amount of available liquidity, to support the significantly larger capital expenditure plan. As of June 2012, Canadian Utilities Limited has two credit facilities totaling $700.0 million, and CU Inc. has two credit facilities totaling $900.0 million. There are different fees associated with each of these credit facilities, from extension fees to standby fees to draw down fees. The costs associated with the credit facilities are shared between Canadian Utilities Limited's and CU Inc.'s subsidiaries using a shared cost formula. ATCO Electric Ltd.'s (transmission and distribution combined) forecast share of these costs is $2.2 million for 2013 and $2.1 million in 2014. These costs are included in corporate A&G costs.

949. In its response to information request CCA-AE-45,[347] ATCO Electric provided calculations of the forecast amounts as well as the allocations. ATCO Electric also confirmed

[346] Exhibit 1, application: Section 31, Attachment 5, Schedule 28-3.
[347] Exhibit 53.01.

that that the costs allocated to it mirrored the actual costs incurred by CU Inc. and Canadian Utilities Limited. In the same response, ATCO Electric explained that its required credit facilities are based on Standard & Poor's criteria, and further explained that one of the key indicators of a company's liquidity cushion is an A/B ratio, defined as "liquidity sources (A) divided by uses (B)." It advised that Standard & Poor's criteria is that, for liquidity to be considered adequate, the liquidity cushion should be about 1.2 or greater.

950. The CCA argued that the liquidity ratio for 2014 provided by ATCO Electric was 1.7, and that the way to adjust this ratio downward to 1.2, is to reduce the level of the credit facilities available to ATCO Electric, which appears to have been acknowledged by a member of the ATCO Electric general witness panel.[348] It submitted that corresponding to this reduction in the level of credit facilities, there should be an adjustment to the cost of credit facilities in 2014, and it recommended that such changes be reflected in the 2014 revenue requirement.

951. ATCO Electric replied that the $1.6 billion in credit facilities in place for CU Inc. and Canadian Utilities Limited is available to all subsidiary companies and not just ATCO Electric. It indicated that it is only receiving approximately 50 per cent of the total costs of the available $1.6 billion, or $800.0 million, and added that, on a stand-alone basis, the $800.0 million would not meet the liquidity requirements as prescribed by Standard & Poor's. ATCO Electric submitted that no reduction in credit facilities is required.

Commission findings

952. The Standard & Poor's criteria were not a factor in arriving at the forecast for the allocated credit facilities costs, and agrees with ATCO Electric that the liquidity ratio calculation provided in the response to information request CCA-AE-045 was incorrect, as acknowledged by a witness on the ATCO Electric general witness panel.[349] The liquidity ratio calculation included the entire $1.6 billion of available credit facilities, when in fact ATCO Electric is only forecasting costs associated with approximately 50 per cent of the $1.6 billion. In addition, the liquidity ratio calculation only includes capital expenditures for the transmission function, while the forecasted costs are for both the transmission function and the distribution function. To be accurate, the liquidity ratio calculation should also include the capital expenditures for distribution, or alternatively, only include the forecast costs for the transmission function. The Commission agrees with ATCO Electric that, based on the transmission capital expenditures included in the application, the correct liquidity ratio calculation would be less than 1.2.

953. The forecast credit facility costs included in the application are simply a result of calculating the costs applicable to the entire $1.6 billion of credit facilities, and then applying the results of the allocation methodology to the total costs, to arrive at ATCO Electric's share. ATCO Electric then further allocates its share between its transmission and distribution functions. No party made any recommendation regarding the costs applicable to the entire $1.6 billion of credit facilities, and the Commission considers that these costs are reasonable.

954. Attachment 1, Schedule 2(a) to the response to information request CCA-AE-45(a) shows that the credit facility costs were allocated to the various CU Inc. and Canadian Utilities Limited subsidiaries using the cost allocation methodology that is based on the average of revenues, assets, and capital expenditures. In Decision 2013-111, the Commission directed that there

[348] Exhibit 235.01, CCA argument, paragraph 128.
[349] Transcript, Volume 2, page 285, lines 1-6.

should be changes to the allocation methodology used to allocate the ATCO Ltd. corporate costs. The Commission considers that, for consistency and for the same reasons it directed the changes to the allocation methodology in Decision 2013-111,[350] the same changes should be made to the revenues, assets and capital expenditures methodology used to allocate the cost of the credit facilities. The Commission directs that the 2011 actuals should be used as inputs in the calculation of the revised methodology, as these represent information from two years prior to the first test period. The Commission commented on this in paragraph 134 of Decision 2013-111.

955. Therefore, with regard to calculating the allocated share of the credit facility costs for 2013 and 2014, the Commission directs ATCO Electric, in the compliance filing, to update these amounts to reflect the following changes it is directing to the revenue, assets and capital expenditures methodology:

- Capital expenditures are to be removed from the allocation methodology.
- Labour expense is to be incorporated into the allocation methodology.
- Gross revenue is to be removed from the allocation methodology and replaced with revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation.

956. The Commission further directs that the resulting revenue figures be given an equal weighting in the formula along with labour expense and total assets.

14.7 Credit metric ratios

957. ATCO Electric provided its forecast credit metrics under the status-quo arrangements (federal FIT, and return on direct assigned capital projects CWIP included in the revenue requirement) and under the assumption that provincial FIT would now be included in the revenue requirement, as proposed by ATCO Electric. It stated that including CWIP in rate base, and the recovery of both federal and provincial FIT, helps to maintain the credit metrics at an appropriate level to sustain an "A" credit rating and not risk a credit rating downgrade.

958. ATCO Electric submitted that even with the proposed additional credit relief of recovering provincial FIT, the funds from operations (FFO)/debt credit metric is under pressure and below the 2011 and 2012 levels. It added that the other credit metrics which factor in the recovery of all three items are considered reasonable to support an "A" credit rating.

959. During the oral hearing, ATCO Electric undertook to provide a further update to the credit metrics, using an assumption that it's direct assigned capital projects expenditures were reduced by 15 per cent for 2012 to 2014 from those presented in the omissions and updates filing. It indicated that even with this hypothetical 15 per cent reduction and the updated reduction to financing rates, the FFO/debt ratio would remain significantly below 15 per cent, and submitted that if the status quo is maintained and provincial FIT are not allowed to be collected, its FFO/debt ratio will fall below the level achieved in 2011 and 2012.

[350] Decision 2013-111, paragraphs 126-135.

960. Mr. Gorman submitted, on behalf of the ADC, that the recovery of provincial FIT is not necessary to support ATCO Electric's credit metrics at an acceptable level.[351] He added that ATCO Electric's historical actual credit metrics have supported its bond rating, are clear evidence of acceptable credit metric targets and that the projected credit metrics without provincial FIT are within the historical range. He also provided credit metric results in support of his evidence.

961. Mr. Bell, representing the UCA, stated in his evidence[352] that the credit metrics for 2013 and 2014 remain above the Commission's thresholds, without the addition of provincial FIT. He also submitted that lower cost alternatives such as federal and provincial FIT (without CWIP in rate base) or CWIP in rate base without any FIT, should be considered. He indicated that the forecast credit metrics for ATCO Electric for a number of credit relief scenarios are at or above the Commission's thresholds.

962. Mr. Bell submitted that, in Decision 2009-216,[353] the Commission determined that an earnings before income tax (EBIT) coverage ratio of 2.0-2.3 appears to be sufficient to obtain credit ratings in the lower "A" range; that it determined that a FFO/debt percentage of 11.1 to 14.3 was sufficient to maintain credit ratings in the lower "A" range and also ruled that a FFO coverage ratio of at least three is associated with credit ratings in the lower "A" range.

963. Mr. Bell indicated, that the Commission reaffirmed these thresholds in the 2011 Generic Cost of Capital decision, and used the same thresholds in its decision on the ATCO Electric 2011-2012 GTA, when assessing the requested credit metric relief from that file. He added that in its 2009-2010 GTA, AltaLink Management Ltd. put forward a target of 10 per cent for the FFO/debt ratio as its sole metric for credit relief, and that AltaLink Management Ltd. reaffirmed this target in its 2011-2013 GTA.

964. ATCO Electric submitted that the 10 per cent FFO/debt ratio target for AltaLink Management Ltd. is specific to that utility and is not a comparable threshold for ATCO Electric. It indicated that the 10 per cent target is a minimum threshold for a downgrade from an "A-" rating to a "BBB" rating, whereas it wishes to maintain CU Inc.'s rating at "A." It added that AltaLink Management Ltd. has also included the collection of provincial FIT as part of its 2013-2014 GTA.

965. ATCO Electric submitted that the credit relief requested should be viewed as an acceleration of cash flows, which results in lower overall costs to customers for new assets, which was acknowledged by the Commission in Decision 2011-134. It indicated that including CWIP in rate base and the collection of federal and provincial FIT are not beneficial to investors, and argued that what is of benefit to investors and customers from maintaining a stable "A" credit rating, is the ability to finance ATCO Electric's significant transmission capital program at the lowest possible debt rates.

966. ATCO Electric responded to Mr. Bell's submission that credit metrics are not applied formulaically, by stating that qualitative factors such as business risk are also contributing factors in arriving at credit ratings. It advised that Standard & Poor's has assessed Nova Scotia Power

[351] Exhibit 88.04.
[352] Exhibit 89.02.
[353] Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.

and Union Gas as having a higher business risk than AltaLink Management Ltd., Fortis Inc., and FortisAlberta Inc., and submitted that the higher business risk, with all other things considered equal, would lead to poorer credit ratings. ATCO Electric added that other items, such as awarded equity thickness, should also be taken into consideration when attempting to draw correlations between credit ratings and credit metrics.

967. ATCO Electric argued that Mr. Bell was admittedly not an expert in the field of credit ratings and required credit metrics and, as such, his evidence should be given no weight. It also submitted that, as clarified by Mr. Bell during the oral hearing, Mr. Bell's views were his own and not those of the UCA. ATCO Electric further submitted that because no representative of the UCA gave evidence at the hearing, the Commission could not consider Mr. Bell's credit metric evidence as being representative of the positions of the UCA. It added that should the Commission be inclined to give Mr. Bell's evidence on credit metrics any weight, it had responded to the substance of his evidence.

968. The UCA submitted that in Decision 2011-134, the AUC did not approve credit metric relief so that ATCO Electric could maintain, or try to maintain, the identical metrics as CU Inc. It argued that to interpret Decision 2011-134 as requiring ATCO Electric to match the credit metrics of CU Inc. would be a significant departure from the past practice of the Commission, given that ATCO Electric has always had lower credit metrics than CU Inc.

969. The UCA stated that the debt rating agency material ATCO Electric placed on the record shows that there is no expectation that CU Inc., much less ATCO Electric, should achieve the 3.5 FFO interest coverage and the 15 per cent FFO/debt ratio. It referred to the following quote from Standard & Poor's that appeared in two reports:

> We view CU Inc.'s financial risk profile as intermediate. In the next few years, funds from operations (FFO) interest and debt coverage should remain stable at about 3.5X and 15%, respectively.[354]

970. The UCA argued that, between the two times Standard & Poor's articulated the 3.5x and 15 per cent thresholds, Alberta Power (2000) was sold by CU Inc. to its parent company Canadian Utilities Limited. It submitted that it was strange that Standard & Poor's would have the same thresholds following this sale, and accordingly these thresholds should be treated with some skepticism. It submitted that no reports issued after the 2011 GTA warn that incremental regulatory relief is required.

971. The UCA recommended that both provincial FIT and federal FIT be denied, and that, at a minimum, ATCO Electric's request for provincial FIT be denied.

972. The ADC submitted that all market participants understand that ATCO Electric's credit metrics will be under downward pressure during the peak of its major build program and will then recover significantly. As such, the minimum credit metrics during this peak are not long-term expected credit metric targets, but rather they are approximations of short period floor metric targets to carry ATCO Electric through the major build program.

973. ATCO Electric submitted that, the Commission did not state in Decision 2011-134, that meeting the minimum credit metric ratios observed in Decision 2009-216 were sufficient credit

[354] Exhibit 237.02, UCA argument, paragraph 54.

metric relief in the context of ATCO Electric's major capital program. It submitted that the ADC's supposition about benefits to shareholders was unfounded speculation, and that ATCO Electric would not be paying dividends but rather would require equity injections. It submitted that discontinuation of federal FIT would result in its FFO/debt percentages being 10.9 per cent for 2013 and 10.6 per cent for 2014, and that these are below the minimum levels for a low "A" credit rating, as observed by the Commission in Decision 2009-216.

974. The UCA addressed ATCO Electric's submission that even with provincial FIT, ATCO Electric's FFO/debt ratio for 2013 and 2014 would drop below the ratio achieved in 2011 and 2012. It submitted that ATCO Electric's credit metrics for 2011 should be higher than the ones for 2010, because 2011 marked the start of including CWIP in rate base and the collection of federal FIT, and it stated that the 2011 actual credit metrics were artificially high because ATCO Electric's capital spending that year was 46 per cent below the forecast amount.

975. With respect to Mr. Bell's evidence, the UCA submitted that his evidence does not independently propose credit metric thresholds, but instead is based on the Commission-identified thresholds, while drawing on Mr. Bell's regulatory and accounting expertise. It stated that Mr. Bell has been qualified by the Commission in the past as an expert in regulatory accounting and that Mr. Bell has deep and significant relevant experience.

976. The UCA addressed ATCO Electric's assertion that the Commission cannot consider Mr. Bell's credit metric evidence as being representative of the positions of the UCA because no representative of the UCA gave evidence as to the UCA's policy perspectives or views. It submitted that Mr. Bell authored evidence under his own name and defended it under cross-examination, and it was clear he was retained by the UCA. In addition, in argument, the UCA adopted Mr. Bell's recommendations. The UCA submitted that under the Commission's rules of practice there is no requirement to seat a policy witness.

977. The UCA submitted that the requirements of natural justice and procedural fairness also do not require the Commission to take any steps now relative to Mr. Bell's evidence or the UCA's argument. It indicated that ATCO Electric asked information requests of Mr. Bell and cross-examined him, had the opportunity to identify and request more relief if desired but did not, and no prejudice arises now from considering the resulting record. It stated that the National Energy Board also recently rejected a similar argument during the TransCanada Mainline restructuring hearing.

Commission findings

978. With respect to the issues raised by ATCO Electric regarding the expertise of Mr. Bell and the weight to be given to his evidence, the Commission understands that Mr. Bell has not held himself out to be an expert in the area of credit metrics. However, the Commission does recognize that Mr. Bell has significant experience in the area of regulatory accounting and in analyzing the cash flows of regulated utilities. The Commission further accepts that the UCA has adopted Mr. Bell's evidence given his qualifications. Further, ATCO Electric has had full opportunity to test Mr. Bell's evidence in this proceeding. Therefore, the Commission will not disregard Mr. Bell's evidence as requested by ATCO Electric, and will consider the weight of Mr. Bell's evidence in a manner that is commensurate with his expertise.

979. ATCO Electric has based its credit metric requirements on the comments and expectations of Standard & Poor's regarding credit metrics for CU Inc. In contrast, Mr. Bell

submitted that the minimum credit metrics were those minimum ranges identified by the Commission in its 2009 Generic Cost of Capital decision, and relied upon by the Commission in its 2011 Generic Cost of Capital decision as being associated with credit ratings in the "A" range.

980. The Commission has also commented on the use of debt rating agency guidelines in setting equity ratios and determining minimum required credit metrics.

981. The Commission said the following in Decision 2009-216:

> 346. The utilities argued that it was necessary for their companies to meet or exceed minimum standards for these metrics in order to maintain a credit rating in the A range. The utilities pointed to some minimum credit metrics published by the bond rating agencies as providing guidance to the Commission. The Commission observes that these "minimum credit metrics" are more in the nature of general guidelines and that they are no longer consistently published by credit rating agencies.
>
> 347. The following table provides the actual credit ratings and corresponding key financial ratios (or credit metrics) for the Canadian utility companies that raise debt independently and for which credit reports were available on the record. The Commission did not include government-owned entities in this table because their credit ratings are heavily influenced by their government ownership status.

Table 12. Credit Rating Metrics

Segment or Utility	Actual Debt Rating(s)	Provider	EBIT Interest Coverage	FFO / Debt (%)	FFO Coverage
AltaLink	A- Stable	S&P	1.7	11.1	3.0
AltaLink	A Negative Trend	DBRS	2.07		
AltaLink Investments L.P. (Parent of AltaLink)	BBB Negative Outlook	DBRS	1.53	10.5	
Fortis Inc.	A-	S&P	2.2	11.5	2.9
FortisAlberta	A (low)	DBRS	2.03		
FortisAlberta	A-	S&P	2.3	14.3	4.2
CU Inc.	A	S&P	2.7	18.7	3.6
CU Inc.	A (high)	DBRS	2.38		

> 348. The Commission observes from the above table that **EBIT coverage ratios of approximately 2.0 to 2.3 appear to be sufficient to obtain credit ratings in the lower A range**. [emphasis added]
>
> 349. EPC submitted that based on S&P guidelines, an interest coverage ratio of 2.3 to 2.8 is required to maintain an A credit rating for "S&P business risk positions 2 to 3" which would be applicable to the distribution business of EPC, and an interest coverage ratio of 1.8 to 2.3 times is required for the lower risk "S&P business risk position of 1 to 2" which would be applicable to the transmission business of EPC. The "business risk positions" to which EPC referred, are business risk rankings formerly employed by S&P. S&P no longer publishes business risk positions. Nevertheless, the Commission observes that if S&P were still using the guidelines cited by EPC, it appears that all of the utilities listed in Table 7 (all of which have investment grade ratings) would be considered in a lower risk category given that their EBIT coverage ratios range from 1.7 to 2.7. In the case of AltaLink Investments L.P., DBRS has assigned a credit rating of BBB with a

> negative outlook where the EBIT coverage ratio is 1.53 times and the "cash flow to debt" (a term used by DBRS that appears to be equivalent to FFO/Debt) is 10.5 percent. This gives the Commission some indication that the lower end of the EBIT coverage range necessary to maintain a credit rating in the A range is approximately 1.8.
>
> 354. Table 14 shows that when the annual depreciation expense as a percentage of invested capital is equal to the utility average of 6 percent, minimum equity ratios in the range of 30 to 36 percent will achieve **FFO/Debt percentages of 11.1 to 14.3, which Table 12 shows is associated with credit ratings in the lower A range**. [emphasis added]
>
> 356. It appears from Table 15 that when the annual depreciation expense as a percentage of investment capital is equal to the utility average of 6 percent, a minimum equity ratio of 33 percent is required to achieve **an FFO coverage ratio of at least 3, which Table [12] shows is the minimum FFO coverage associated with credit ratings in the lower A range**. [emphasis added] [all footnotes in these quoted paragraphs have been omitted]

982. Consistent with Decision 2009-216, the Commission rejects ATCO Electric's submission that it should rely on Standard & Poor's stated expectations for credit metrics, and instead will continue to rely on the minimum credit metrics that debt rating agencies are observed to actually be associating with credit ratings in the "A" range for utilities. In the Commission's view, no new information on these actually observed minimum requirements has been presented subsequent to Decision 2009-216.

983. The Commission's approach continues to be to provide credit metric relief with a goal of maintaining the minimum credit metrics that have been observed to be associated with relatively pure play Canadian utilities that have "A" range credit ratings. While ATCO Electric has argued that higher credit ratings are needed during periods of large capital expenditures, no evidence was presented based on actual utility credit ratings and credit metrics.

984. ATCO Electric's position on the need to collect provincial FIT relied on the need to meet the credit metrics it proposed were required. The Commission agrees with the UCA's analysis that the collection of provincial FIT is not required to meet the credit metrics determined as set out in Decision 2009-216, and therefore denies ATCO Electric's request to recover provincial FIT. The Commission directs ATCO Electric, in the compliance filing, to remove provincial FIT from the income tax component of the revenue requirements for 2013 and 2014, and to update the remaining revenue requirement schedules as applicable, to reflect the removal of provincial FIT.

985. Consistent with the requirement to meet the credit metrics set out in Decision 2009-216, the Commission considers that all three credit metrics are important. While the UCA recommended that provincial FIT and federal FIT should be denied, the UCA's own analysis in paragraph 48 of its argument[355] indicates that this would not satisfy the minimum FFO/debt ratio, as ATCO Electric's resulting FFO/debt ratio would be 10.9 per cent for 2013 and 10.6 per cent for 2014.

986. The Commission considers that it is important that all three of the credit metrics be reasonably expected to be achieved on a forecast basis, and the inclusion of direct assigned

[355] Exhibit 237.02.

capital projects CWIP in rate base, and federal FIT, achieve this goal based on the information contained in ATCO Electric's omissions and updates filing. The Commission therefore denies the request from the UCA that federal FIT not be included in the revenue requirement. The Commission considers that it is also important from a consistency point of view to maintain the inclusion of federal FIT in the revenue requirement, and direct assigned capital projects CWIP in rate base. This should signal to credit rating agencies that the Commission is committed to maintaining credit metrics at the same level as approved in Decision 2009-216.

987. The Commission finds that the approvals it has made for the 2013 and 2014 test period in this decision are on a prospective basis, and therefore should not be based on any assumptions that the actual results for 2013 and 2014 will be different. Therefore, the Commission has disregarded the UCA's suggestion about what the actual credit metrics will be for 2013 and 2014 if the full revenue requirement is not spent.

14.8 Revenue requirement mitigation plan proposed by ADC

988. Mr. Gorman, representing the ADC, proposed a "balanced regulatory plan" whereby customers would continue to provide extra payments for credit metric relief during the construction phase (federal FIT and direct assigned capital projects CWIP in rate base), but rates would then be reduced for a period of ten years with the reduction recovered thereafter. The details associated with this revenue requirement mitigation plan are included on pages 15 to 18 of Mr. Gorman's evidence.[356]

989. ATCO Electric argued that the ADC's proposal addresses issues that occur after the major construction program is completed, which would occur outside of the test period and are therefore not in the scope of the current application. It added that the TFCMC has established a sub-committee, the TCRS, which has a mandate to work with other stakeholders, including the ADC, to explore and develop approaches for rate design that would benefit both current and future consumers of electricity. It stated that the Government of Alberta has indicated that it will be directing the AUC to conduct a public transmission cost recovery inquiry, following receipt of the TCRS's preliminary options.

990. ATCO Electric submitted that, given that these initiatives are still underway and under review by the government of Alberta, it would be premature and inefficient to consider the ADC's proposal in isolation in the context of this GTA. It also submitted that the ADC had not provided the specifics of its plan, including the accounting implications.[357]

991. The ADC acknowledged that it did not offer specific plans for a balanced regulatory system, and it recommended that the Commission approve the general objective of initiating a balanced regulatory plan during and after construction. It stated that if a balanced regulatory plan can maintain strong credit metrics, and provide full cost recovery, while protecting the current generation of customers, all stakeholders to the process will benefit. It added that the details of achieving these objectives will be complex, and can be developed in detail in the next GTA or special regulatory proceeding.

[356] Exhibit 88.04.
[357] Exhibit 239.01, ATCO Electric argument, paragraphs 272 to 274.

Commission findings

992. The revenue requirement mitigation plan proposed by the ADC is not detailed enough for the Commission, to fully examine it and understand all of its implications, including any possible effects on credit ratings. The ADC did not provide any specific comments from rating agencies with regard to its revenue requirement mitigation proposal. Under questioning from Commission counsel, Mr. Gorman explained that he has experience with regulatory plans, that were considered in very detailed review, in credit rating agencies' assessments of the credit ratings of utilities.[358] In this current case, the Commission finds that there has not been a detailed review of the ADC's plan because, as acknowledged by the ADC itself, it did not provide enough specifics on how its plan would achieve regulatory balance. If there are no specifics to examine, there is uncertainty with respect to the response that would be received by the credit rating agencies.

993. Also during the oral hearing, Mr. Gorman acknowledged that the revenue requirement mitigation plan proposed by the ADC in this application is similar to the "mirror CWIP" proposal that was discussed during the 2011-2013 GTA of AltaLink Management Ltd. In paragraphs 939 to 943 of Decision 2011-453 on AltaLink Management Ltd.'s 2011-2013 GTA, the Commission expressed the same concerns about how the "mirror CWIP" plan would be perceived by the rating agencies. The ADC did not present anything in this current proceeding that would alleviate these concerns.

994. As referenced by the ADC and ATCO Electric, the Commission has initiated a coordinated process to examine alternative approaches and rate treatments that might mitigate or smooth the impact on customers of rate or bill increases associated with transmission investments, in addition to ensuring that regulated utilities continue to have a reasonable opportunity to earn a fair return on capital. The ADC itself stated that while its revenue requirement mitigation plan will not fully address the significant rate impact customers will be experiencing, it can be one of the rate mitigation strategies that the government of Alberta has recently directed the AUC to explore. The Commission agrees that the ADC's revenue requirement mitigation plan would be better suited for further discussion, and possible refinement, during the Commission's coordinated process, and encourages the ADC to participate in this process.

995. With respect to the ADC's recommendation that the Commission approve the general objective of initiating a balanced regulatory plan during and after construction, the Commission is not prepared to approve the general objective, at this time.

996. Based on its findings and considerations with respect to this issue, the Commission denies the revenue requirement mitigation plan brought forward by the ADC for use in calculating ATCO Electric's transmission revenue requirements for the years 2013 and 2014.

15 No cost capital

15.1 No cost capital – future income taxes

997. The Commission reviewed schedules 7-2 (Schedule of Transmission Income Taxes) and 29-3 (Schedule of Future Income Taxes) of the supplementary revenue requirement schedules[359]

[358] Transcript, Volume 7, page 1394, lines 9-11.
[359] Exhibit 188.02.

that were filed in conjunction with the omissions and updates filing, and questioned why the future tax amounts for 2011 and 2012 in Schedule 29-3 did not agree with the corresponding cross referenced amounts in Schedule 7-2.

998. In response,[360] ATCO Electric advised that the current year future tax balances in Schedule 29-3, of $6.7 million and $10.9 million for the years 2011 and 2012, reflect those final amounts which were approved and collected in rates as part of ATCO Electric's 2011-2012 GTA compliance filing, adding that it only includes in no cost capital those balances which were approved and collected in rates, as opposed to the actual amounts that it incurs.

999. This explanation is valid because the amount of FIT included in no cost capital should include the amounts which were approved and collected in rates. The AESO has paid the approved amounts and these approved amounts should be reflected in the calculation of mid-year no cost capital and ultimately the return on rate base.

Discussion of the issues

1000. The CCA expressed a concern with the forecast balances included in the no cost capital account for FIT, adding that the mid-year FIT balance was $3.4 million in 2011, but it is forecast to be $90.4 in 2014. It submitted that there is no evidence that these FIT balances are needed or required to mitigate credit metric pressures in the current year, and they should be refunded to customers as soon as possible. The CCA recommended that ATCO Electric be directed to file, in the compliance filing, a proposed method to refund the balances accumulated in the no cost capital account for FIT.

1001. ATCO Electric argued that it has provided evidence that the collection of FIT is necessary to address the need for credit metric relief, and added that the purpose of adopting measures such as FIT is to provide the utility with additional cash to finance capital programs, thereby alleviating to some extent negative cash flow, which puts pressure on its credit metrics. ATCO Electric indicated that the issue of potentially refunding no cost capital balances was raised with respect to capitalized pension balances, and that in Decision 2012-331[361] the Commission rejected the proposal.

Commission findings

1002. In Section 14.7 of this decision the Commission has rejected ATCO Electric's request to recover provincial FIT as part of the revenue requirements for 2013 and 2014. The Commission directs ATCO Electric, in the compliance filing, to update the applicable no cost capital schedules to reflect this finding.

1003. The Commission has discussed ATCO Electric's credit metrics and request for the collection of federal and provincial FIT in Section 14.7 of this decision, and determined that while the collection of federal FIT is required to maintain credit metrics at an acceptable level, the collection of provincial FIT is not required. The Commission finds that this should somewhat alleviate the CCA's concerns about the balances in the FIT no cost capital account, because those balances will be smaller in the compliance filing. Having approved the collection of federal FIT,

[360] Exhibit 226.01, response to AUC-AE-003.
[361] Decision 2012-331: ATCO Utilities (ATCO Gas, ATCO Pipelines (divisions of ATCO Gas and Pipelines Ltd.) and ATCO Electric Ltd.), 2011 Pension Common Matters Second Compliance Filing, Application No. 1608750, Proceeding ID No. 2078, December 7, 2012.

it is not necessary for ATCO Electric to provide any kind of plan with respect to refunding those balances. The Commission is aware that customers are given credit for the FIT through the reduction to mid-year rate base, a fact that the CCA also acknowledged. For the reasons discussed in this section and Section 14.7 of this decision, the Commission rejects the submission of the CCA that ATCO Electric be directed to file, in the compliance filing, a proposed method to refund balances accumulated in the no cost capital account for FIT.

15.2 No cost capital – cash contributions for pension capitalized

1004. The Commission reviewed schedules 29-5 (Schedule of Cash Contributions for Pension Capitalized) and 29-6 (Calculation of Pension Contributions) of the supplementary revenue requirement schedules[362] that were filed in conjunction with the omissions and updates filing, and questioned why the capital pension contribution for 2012 in Schedule 29-5 did not agree to the corresponding cross referenced amount in Schedule 29-6.

1005. In response,[363] ATCO Electric advised that the capitalized pension amount of $5.3 million for the year 2012 in Schedule 29-5 reflects the final amount approved and collected in rates as part of ATCO Electric's 2011-2012 GTA compliance filing. It added that it only includes in no cost capital those balances which were approved and collected in rates, as opposed to the actual amounts that it incurs.

Commission findings

1006. The Commission accepts ATCO Electric's explanation that the amount of capitalized pension contributions included in no cost capital should include the amounts approved and collected in rates. The AESO has paid the approved amounts and these approved amounts should be reflected in the calculation of mid-year no cost capital and ultimately the return on rate base.

16 Affiliate transactions

1007. Other than the issue raised by the RPG, with respect to the concerns it has with the inter-affiliate code of conduct not applying to purchases for services from an affiliate of ATCO Electric by a third-party contractor, no other party raised any issues with respect to affiliate transactions. The Commission has addressed the RPG's concerns in Section 11.9.5 of this decision relating to capital projects.

1008. In paragraph 392 of the application,[364] ATCO Electric requested that the volumes for ATCO I-Tek, as detailed in schedules 30-9 and 30-10, be approved as part of this application. However, in response to information request UCA-AE-023(b),[365] ATCO Electric advised that this was a typo, and that it was requesting approval of the volumes for ATCO I-Tek as detailed in schedules 30-13 and 30-14.

1009. The Commission directs ATCO Electric, as part of the compliance filing, to update any schedules in Section 30 of the application, to reflect any updated amounts included in the supplementary revenue requirement schedules that will be submitted as part of the compliance

[362] Exhibit 188.02.
[363] Exhibit 226.01, response to AUC-AE-006.
[364] Exhibit 1, application, Section 30.
[365] Exhibit 51.01.

filing, so that the schedules are consistent. The Commission further directs ATCO Electric to prepare schedules 30-12, 30-13 and 30-14 in the same format used in the application, which included the corporate totals for isolated generation, general O&M, common operations, and corporate A&G. The Commission has also previously directed ATCO Electric, in Section 5.2.1 of this decision, to submit supplementary schedules that show only the transmission function's share of the ATCO I-Tek volumes for 2013 and 2014.

17 2011 deferral account and annual filing for adjustment balances

1010. ATCO Electric requested approval of a number of deferral account balances related to the year 2011, and of certain amounts relating to other matters. It also included details of the carrying costs it had calculated with respect to each of the deferral accounts and other adjustments, up to the forecast refund date of May 2013.

1011. ATCO Electric requested approval of the following amounts:

Table 49. 2011 deferral account balances and filing for adjustment balances as requested by ATCO Electric

		Collect from (refund to) the AESO ($ million)
Isolated generation fuel costs		(2.304)
Direct assigned capital projects		(12.881)
Income tax - deduction of deferrals		1.696
Income tax – deductible capital costs		.015
Variable pay program		3.661
Right-of-way payments		(.477)
Taxes other than income		(1.110)
TOTAL DEFERRAL ACCOUNT BALANCES	(a)	(11.400)
2011-2012 generic cost of capital adjustment		(1.300)
Tax claims – Slave Lake and northern wildfires		(.114)
TOTAL ADJUSTMENT BALANCES	(b)	(1.414)
2011 carrying costs		.651
2012 carrying costs		(.296)
2013 carrying costs		(.122)
TOTAL CARRYING COSTS	(c)	.233
TOTAL BALANCE	(a)+(b)+(c)	$(12.581)

1012. The resulting total balance is a refund to the AESO of approximately $12.6 million. During the oral hearing, an ATCO Electric witness advised that an update was required to the direct assigned capital projects deferral account balance, to account for some land that was not

required for utility purposes,[366] and that this update would be made as part of ATCO Electric's compliance filing.

1013. The Commission agrees that the direct assigned capital projects deferral account balance should be updated to account for this disposition, and considers that any property taxes related to this land that were paid in 2011 should be removed from the calculation of the "taxes other than income" deferral account balance for 2011. The Commission directs ATCO Electric, in the compliance filing, to update the calculation of the direct assigned capital projects deferral account balance for 2011 to reflect the disposition of the land described in Decision 2013-221,[367] to advise whether any property taxes were paid on this land during 2011, and to exclude such property taxes from the calculation of the 2011 "taxes other than income" deferral account balance.

1014. The Commission has verified that its approval for the establishment of the deferral accounts included in Table 49 above, was given in Decision 2011-134 respecting ATCO Electric's 2011-2012 GTA, and it finds that the calculations of the deferral account balances that ATCO Electric submitted as part of the application are correct, with the exception of the corrections required, as discussed in the previous paragraph. As previously discussed in Section 11.9.4 of this decision, the actual 2011 capital additions for the HRTD program are placeholders, because this program will be the subject of a subsequent audit.

1015. ATCO Electric advised that the reason for the balance in the VPP deferral is that it increased its VPP eligibility in 2011 from 40 per cent of it's out of scope employees to 70 per cent, which resulted in the VPP payouts in 2011 being $3.661 million more than the approved forecast. It explained that, in applying for continuation of the VPP deferral account in the 2011-2012 GTA, the deferral account balance would be calculated by taking the difference between the approved VPP forecast amount and the actual VPP paid out. The Commission agrees with ATCO Electric that this calculation method for the VPP deferral account for the years 2011 and 2012 was approved, and it is consistent with the approval of the VPP deferral account balance for 2011 for ATCO Electric's distribution function, that was granted in Decision 2013-036.[368]

1016. The RPG recommended that the Commission reserve the right to conduct cost and performance audits on a couple of 2011 direct assigned capital projects, identified as Sulphur Point – High Level 144-kV line (Project 51060) and Ring Creek Arcenciel – 144-kV line and substation (Project 51081). The topic of cost and performance audits, and whether these two projects should be subject to a cost and performance audit, is discussed in more detail in Section 11.9.4 of this decision.

1017. ATCO Electric included a refund of $1.3 million to the AESO with respect to the generic cost of capital adjustment for the year 2011, and explained that its 2011 revenue requirement had been approved based on a return on equity placeholder of nine per cent. It advised that in the 2011-2012 generic cost of capital decision (Decision 2011-474), the AUC approved a return on

[366] Transcript, Volume 4, page 634, lines 6-25; page 635, lines 1-14.
[367] Decision 2013-221: ATCO Electric Ltd., Disposition of Surplus Land at Heathfield Converter Station, Application No. 1609479, Proceeding ID No. 2550, June 13, 2013.
[368] Decision 2013-036: ATCO Electric Ltd., 2011 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Application No. 1608611, Proceeding ID No. 1990, February 8, 2013.

equity for 2011 of 8.75 per cent, adding that the resulting impact on the 2011 revenue requirement of using 8.75 per cent instead of nine per cent, was $1.3 million.

1018. ATCO Electric stated that the amount of ($0.114) million in the tax claims for the Slave Lake and northern wildfires, is comprised of two components. The first component is made up of costs incurred for dismantling assets that were damaged in the fires, which are deductible for income tax purposes in the period they were incurred. The second component is made up of additional capital cost allowance deductions that were claimed on the capitalization of new assets as a result of the fire, in accordance with IFRS. Details of the calculation of the ($0.114) million are found in Schedule 11.0 of Section 32 of the application.

1019. ATCO Electric is seeking recovery of the costs incurred as a result of the Slave Lake and northern wildfires through the reserve for injuries and damages account and, as such, considered it appropriate to pass along to the AESO the expected tax savings associated with the additional tax deduction described in the previous paragraph. It stated that the Canada Revenue Agency has not audited, and therefore not approved, these additional 2011 tax deductions, that any subsequent disallowances of these deductions by the Canada Revenue Agency would result in ATCO Electric recalculating these tax savings and collecting the resulting differences from the AESO in a subsequent deferral application, and that any interest and penalties levied by the Canada Revenue Agency would also be collected from the AESO.

1020. The Commission considers that the calculations supporting the adjustment amount for 2011 are correct. It is not necessary to address ATCO Electric's suggestion with respect to any future disallowances of these amounts by the Canada Revenue Agency, because no such disallowances have occurred. If such a disallowance does occur, ATCO Electric is free to bring this issue forward as part of a subsequent annual filing for adjustment balances application.

1021. Included in the 2011 carrying costs is an amount of $0.679 million that is related to the difference between the amounts ATCO Electric billed on an interim basis during 2011, and its final approved 2011 transmission tariff. In Decision 2010-599,[369] in which the Commission approved the 2011 interim tariff, it stated at paragraph 25 that it considered that utilities can be kept whole by using carrying costs during the transition from one revenue requirement to another.

1022. The Commission finds that ATCO Electric's request for carrying costs in this instance is reasonable, and it has included a direction in paragraph 1024 of this decision that will result in the amount of $0.679 million being updated.

1023. ATCO Electric included carrying costs to the end of May 2013. This needs to be updated to reflect the fact that the deferral account balances were not approved at the end of May 2013, and will not be approved as part of this decision because of updates that are required in the compliance filing. Therefore, the Commission directs ATCO Electric, in the compliance filing, to update the carrying costs calculations to reflect ATCO Electric's expected date for the one time refund of the deferral account balances to the AESO.

1024. During its review of the carrying costs calculation in Schedule 12.0 of Section 32 of the application, the Commission observed that, included in the calculation of the $0.679 million

[369] Decision 2010-599: ATCO Electric Ltd., 2011 Interim Distribution Tariff and Transmission Facility Owner's Tariff, Application No. 1606728, Proceeding ID. 918, December 21, 2010.

carrying costs associated with the 2011 interim to final true up amount, are carrying costs for the months of January 2012 to May 2013 inclusive, even though there is no principal balance associated with the "AESO interest" category for these months. Because the principal balance was no longer in place for these months, ATCO Electric is not entitled to carrying costs for these months. The Commission directs ATCO Electric, in the compliance filing, to not include any carrying costs associated with the "AESO Interest" category for any month after December 2011.

1025. The Commission will further consider the 2011 deferral account balances and annual filing for adjustment balances as part of the compliance filing, and consequently will not approve any of the amounts in Table 49 as part of this decision.

18 Other areas

18.1 Variable pay program

1026. ATCO Electric indicated that in 2006, it introduced a VPP for its senior managers as part of the company's total compensation package, and added that since that time it has taken a measured growth approach to expanding the VPP based on market requirements.

1027. Consistent with the 2011-2012 GTA, ATCO Electric designed the VPP structure to include a subset of the overall corporate metrics as well as an individual goal structure that incorporates the year-end performance appraisals. ATCO Electric added that each employee on the VPP has the following VPP goals structure:

- ATCO Electric's corporate metrics target (which are developed corporately)
- departmental targets (which are developed by the employee's vice-president)
- personal work goals (which are established by the vice-president, manager and the employee)
- developmental plan (which is established by the vice-president, manager and the employee, with very specific developmental tasks, training and opportunities)

1028. ATCO Electric stated that included in its requested VPP, is a component no greater than 10 per cent, related to the net income of ATCO Electric. It added that the Commission has previously approved a 10 per cent weighting for net income and submitted that customers will benefit from cost savings achieved in pursuit of the net income goal in 2013 and 2014.

1029. In the response to information request ADC-AE-097(c),[370] ATCO Electric indicated that its forecast total VPP payments for the 2013 and 2014 test period are based on 90 per cent of the out-of-scope (or non-union) employees in the organization being eligible for VPP. It also stated that the eligibility rate was approximately 70 per cent in 2011 and it was forecasting this to be approximately 90 per cent for the year 2012.

1030. Schedule 25-11 of the application includes more details about the total VPP amounts included in the forecast for the 2013 and 2014 test period, and line 23 of that schedule includes forecast VPP amounts of $10.2 million in 2013 and $11.2 million in 2014. Of these amounts

[370] Exhibit 52.01.

ATCO Electric will expense $1.6 million in 2013 and $1.8 million in 2014, while the remaining amounts will be capitalized.

1031. ATCO Electric advised that it had engaged Mercer (Canada) Limited (Mercer) to review the compensation levels for 364 out-of-scope non-executive employees.[371] Four benchmark position categories were included in the Mercer report as follows:

- business support services
- people leadership
- professional
- technical

1032. ATCO Electric stated that based on the conclusions of the report prepared by Mercer, as well as its own observations with respect to a tight current and ongoing labour market, it was proposing a continued progression of the VPP eligibility rates from approximately 70 per cent in 2011 to approximately 90 per cent in 2012, 2013 and 2014. It submitted that competing pressures from the marketplace, including other Alberta utilities, to hire and retain skilled employees, makes the increase in the VPP eligibility rate key to ATCO Electric's future success.

Discussion of the issues

1033. The CCA expressed concern that the 10 per cent ceiling for the component of VPP related to net income was applied to ATCO Electric's overall VPP budget instead of VPP for individual positions, and submitted that setting the 10 per cent net income ceiling in relation to individual VPP amounts would mitigate any perverse incentive on the part of senior officers and managers, who are eligible to have VPP based on net income metrics, to unduly expand the scope or level of overall payouts under the VPP budget. The CCA recommended that the 10 per cent ceiling on VPP applicable to net income metrics be determined in relation to individual VPP amounts rather than the overall VPP budget for each of the test years, and indicated that the Commission had expressed a similar perspective on the 10 per cent ceiling applicable to VPP based on net income metrics, in paragraph 751 of Decision 2011-450.[372]

1034. While the UCA supported some of the principles for expanding the VPP, it submitted that the scope of the expansion should be reduced to the leadership group of employees, because it appears to be most threatened from a retention perspective. Alternatively, the UCA indicated that a more reflective peer group of utilities could form the basis for a study.

1035. The UCA submitted that retaining key staff allows the utility to achieve efficiencies and minimize costs in a way that large turnover would not, but argued that ATCO Electric's recruitment challenges must be understood within the context of dramatic additions to staff. The UCA submitted that ATCO Electric increased its FTE count by 125 per cent in the previous test period, and seeks to increase it by another 25 per cent in this test period, adding that the actual

[371] The report is included in Exhibit 1, application, Section 25, Attachment 1. As part of the omissions and updates filing (Exhibit 117.01, Attachment 3) ATCO Electric submitted an updated Mercer report that includes AltaLink Utilities Limited in the comparator group.

[372] Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011.

vacancy rates were negative 25 per cent and negative 30 per cent in 2010 and 2011, respectively, which demonstrates that ATCO Electric has clearly had recruiting success.

1036. The UCA observed that the Mercer study's conclusions are based on a comparison group that includes a significant fraction of Calgary-based energy companies. While the comparison group appropriately includes other utilities, the UCA disagreed with the premise that ATCO Electric's compensation should directly compete with major energy companies. The UCA submitted that although consideration of competition with the energy industry may be appropriate, if job comparisons are made at a more granular level than the four broad categories presented, they are different industries with different pay scales.

1037. ATCO Electric submitted that it had provided the Mercer report to support the need for its VPP expansion. It argued that its request is supported by market information, and is required in order for ATCO Electric to remain competitive in the marketplace. It reiterated that VPPs are a common and recognized component of overall compensation in the industry, and that it requires similar programs in order to be able to attract and retain the necessary workforce.

1038. In response to the CCA's recommendation on the 10 per cent ceiling cap for the VPP component related to net income, ATCO Electric submitted that it has administered the program in a manner consistent with prior AUC decisions since its inception. ATCO Electric discouraged the Commission from attempting to micro-manage the program in a manner that could diminish its effectiveness, at a time when attraction and retention of employees is extremely critical. It submitted that the program, in its current form, has been extremely successful, and that any changes to it may risk reversing ATCO Electric's recent successes in meeting its FTE requirements.

1039. In response to the UCA's comments regarding the scope of the VPP, ATCO Electric submitted that a number of the UCA's concerns appear to be linked to the perception that a significant increase in FTEs are required over the test period. It argued, however, that a majority of these employees were hired prior to the test years and the FTE additions for the test years are relatively modest compared to past periods. ATCO Electric added that it is confident that it will be able to hire the required FTEs, particularly if it has a mechanism such as a VPP at its disposal.

1040. With regard to the UCA's concerns about the comparator group considered by Mercer, ATCO Electric submitted that it does not dictate the comparator group established by Mercer. However, it confirmed that it does compete in many areas with various companies, beyond a narrow utility framework, in order to attract and retain required employees. ATCO Electric submitted that the Mercer report provides strong evidence to support the expansion in the scope of the VPP requested.

Commission findings

Net income component

1041. The Commission agrees with the CCA that the 10 per cent ceiling on VPP applicable to net income metrics should be determined in relation to individual VPP amounts and not the overall VPP budget. The Commission reiterates its findings from Decision 2011-450 that a net income component greater than 10 per cent might result in an inherent conflict between shareholder interests and customers. If ATCO Electric wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders.

1042. This should not diminish the effectiveness of ATCO Electric's efforts to attract and retain employees, because these potential employees will still be eligible for VPP. The Commission is not eliminating the entire VPP for these positions, but rather is requiring ATCO Electric to revise the structure of the VPP for these positions. This adjustment only applies to a small number of senior individuals. The Commission directs ATCO Electric, in the compliance filing, to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent.

Eligibility

1043. The Commission recognizes that ATCO Electric did not dictate the comparator group established by Mercer in the preparation of the Mercer report. With respect to the UCA's suggestion that a more reflective peer group of utilities could form the basis of a compensation study, this list of companies would be quite small and therefore may not represent a valid comparator. In addition, even when the Mercer report was revised to include AltaLink Management Ltd.,[373] the overall conclusions did not change.

1044. While the UCA submitted that downtown Calgary energy companies do not reflect a comparison group for an electric transmission utility headquartered in Edmonton with field locations across rural Alberta; these downtown Calgary energy companies, including Syncrude Canada Ltd. and Suncor Energy Inc.,[374] would also have employees located in different areas across the province, including Fort McMurray, where ATCO Electric also has employees.

1045. The UCA has provided no evidence as to why only leadership employees appear to be the most threatened employee group from a retention point of view.

1046. ATCO Electric submitted that the FTE additions in the test period are relatively minor compared to past periods. The Commission therefore considers that the main goal behind the expansion of the VPP eligibility to 90 per cent in 2013 and 2014 is for the retention of employees. Despite the eligibility of VPP for 2011 and 2012 being approved at 40 per cent,[375] ATCO Electric expanded the actual program to 70 per cent eligibility in 2011, and is forecasting to expand it to 90 per cent in 2012. Despite the VPP amounts being subject to deferral treatment in 2011 and 2012, and potentially denied, ATCO Electric must justify that these expenditures have been prudently incurred. ATCO Electric's own actions in expanding the eligibility for the VPP in 2011 and 2012, even before the additional payment amounts are approved for collection, is evidence that it considered these expenditures to be necessary in order to attract and retain staff. In addition, no party has presented any evidence that the expansion was not warranted. Indeed, no party has objected to the inclusion of the 70 per cent eligibility actual VPP payment amounts included in the 2011 deferral account that was filed as part of this application.

1047. The Commission considers that the request to expand the VPP eligibility to 90 per cent in 2013 and 2014 is reasonable, and necessary to retain out-of-scope employees, and consequently rejects the recommendation by the UCA to restrict the 90 per cent eligibility to only the leadership employees.

1048. Although the Commission has approved the expansion of the VPP eligibility in 2013 and 2014 to 90 per cent, it considers that a reduction to the forecast VPP amounts included in the

[373] The revised Mercer report is included in Exhibit 117.01, Attachment 3.
[374] As shown on Appendix A of the Mercer report in Exhibit 117.01, Attachment 3.
[375] Decision 2011-134, paragraphs 304-310.

revenue requirements for 2013 and 2014 is warranted. While ATCO Electric did include the number of FTEs eligible for the VPP in 2013 and 2014, it did not include any details of how the forecast VPP amounts for 2013 and 2014 were calculated, and the assumptions used in arriving at these forecast amounts are not known to the Commission. These assumptions would include what time of the year the VPP payouts are forecast to be made; whether any contingencies were made to reflect the chance that some FTEs would no longer be working for ATCO Electric when the VPP payouts are made and therefore would not receive any VPP; the salary amounts used in the calculation; the net income figures used in the calculation; what target levels were set for employees in order to be paid the forecast VPP amounts; and whether there were any contingencies included to reflect the chance that employees may not achieve 100 per cent of the targets that were set.

1049. ATCO Electric is responsible for demonstrating the reasonableness of its forecast amounts. ATCO Electric has not provided any of the assumptions upon which it relied in calculating its VPP forecasts. In the circumstances, it is not unreasonable for the Commission to assume that not all of the employees eligible for VPP will meet 100 per cent of the targets set for them, and that not all FTEs eligible for VPP will be with ATCO Electric when the VPP payouts are made. Consequently, a reduction to the VPP forecast amounts is required because ATCO Electric has not demonstrated that a 100 per cent payout is justified, and the Commission considers that only 90 per cent of the forecast payout can reasonably be included in revenue requirement, after the revision directed in paragraph 1042 of this decision is made. The Commission directs ATCO Electric, in its compliance filing, to reduce the resulting entire VPP amounts for 2013 and 2014 by 10 per cent in each year.

1050. In response to an undertaking given by an ATCO Electric witness,[376] ATCO Electric acknowledged that certain corrections were required in schedules 23-1, 24-1 and 25-11 with respect to VPP amounts for general O&M employees. In that undertaking response ATCO Electric stated that it would reflect these amendments to the three schedules in the compliance filing. The Commission considers that for the sake of completeness these corrections should be made and therefore directs ATCO Electric, as part of the compliance filing, to include the corrections identified in Exhibit 146.01.

18.2 Historical schedules

1051. As previously discussed in Section 3 of this decision, in Decision 2011-134, the Commission directed ATCO Electric, in all future tariff application, to file applied for, actual, and approved amounts for the years 2003 through to and including its test years. In Section 31, Attachment 5 of this application, ATCO Electric provided this information.

1052. ATCO Electric argued that, while this information may be useful in certain circumstances to provide historic trends over time, it is skeptical that such historic information provides a valid basis for determining reasonable costs in the context of the current GTA. ATCO Electric submitted that a more reasonable approach is to return to the past practice of complying with the Commission's MFR.

1053. The RPG replied that historical information has proven to be exceptionally valuable in establishing reasonable benchmarks for costs, identifying trend changes, and determining whether cost increases are reasonable. It added that it used historical information to demonstrate

[376] Exhibit 146.01.

the bias in ATCO Electric's capital forecasts. It further argued that return to past practices is inappropriate, due to the relatively large increases in capital expenditures expected in the next few years.

Commission findings

1054. The Commission considers that most of the effort required with respect to producing the information ATCO Electric provided in Section 31, Attachment 5 of the application has already been made. Minimal effort should be required in ATCO Electric's next GTA to produce this information, because the only information that will have to be updated will be the 2012 actuals as well as the relevant information with respect to the years 2013 and 2014, which ATCO Electric would be required to update under the MFR in any event.

1055. The Commission found the historical information provided to be relevant and helpful in assessing cost levels and ATCO Electric's forecasting accuracy, as shown in this decision in respect of fuel costs (Section 6) and annual structure payments (Section 7.1.5). The benefits of ATCO Electric continuing to provide this information in future GTAs outweigh the minimal cost and effort required to produce such information. The Commission rejects ATCO Electric's request on this basis.

18.3 Surplus assets

1056. Mr. Bell, on behalf of the UCA, stated that there is no information available describing how assets are identified as being no longer needed to provide utility service. He also added that there is no information available describing how assets that may become no longer needed to provide utility service are identified, and that a utility must be required to provide a rigorous assessment of its asset base to demonstrate that there are no assets included in the rate base that are no longer required to provide utility service, even if it is capable of providing such service. He recommended that the Commission direct ATCO Electric to provide such a rigorous assessment, and submitted that customers should not be liable for the cost of surplus capacity.

1057. Mr. Bell is concerned over the possibility of surplus assets with respect to the Nisku panel shop facility and the land at the Drumheller service building, and also over the possibility of surplus capacity on the telecommunications system. The UCA submitted that the Commission should direct ATCO Electric to refine its current processes to identify facility components that can be removed from rate base on an ongoing basis, and in a fashion that can be readily tracked and tested. It also recommended that the portion of the Drumheller lands that are surplus be removed from rate base until such time as the land is used to provide utility service. It made no recommendation with respect to surplus capacity.

1058. The UCA identified the Drumheller lands as the 14 acre industrial site on the outskirts of Drumheller, adding that a large proportion of this industrial site is currently not being used, and may not be used after a new two story administrative and technical building is built at the site.

1059. ATCO Electric referred to the business case for the Drumheller service building capital project and added that, as detailed in that business case, the new facility, including the use of 14.391 acres of land, will allow the Drumheller office to meet its working, material and equipment storage needs, adding that the cost of the land was $50,000.

1060. ATCO Electric indicated that it has a wide variety of inspections performed routinely by operational staff related to maintaining existing assets, identifying any maintenance or

improvements required to those existing assets, and identifying the necessary retirement and replacement of existing assets. It added that these inspections ensure that its assets are used and required to be used to provide safe, reliable electrical service. ATCO Electric submitted that it only acquires sufficient land to meet its needs and that for facilities such as a service centre, where there is a firm long-term need, it prefers to own rather than to lease. ATCO Electric added that this decision is made on a project-by-project basis, and therefore there is no need for some form of direction regarding a rigorous assessment as proposed by the UCA.

1061. The UCA submitted that the Court of Appeal's *Salt Caverns* decision[377] and subsequent Commission consideration of the issues, are clear that a fractional portion of an asset that is not used and required to be used for utility purposes can, and should be, removed from rate base immediately, and that the utility does not need to partition and sell the fraction or dispose of the asset first. The UCA stated that current and future portions of the Drumheller yard, the Drumheller administrative site, and the Borealis building are all examples of unused assets remaining in ATCO Electric's rate base out of caution rather than usefulness, adding that the inspection process ATCO Electric described failed to identify or even consider these surplus elements.

Commission findings

1062. In its information request UCA-AE-030(a), the UCA made the following request to ATCO Electric:

> Please confirm that all assets included in actual rate base are required for utility service. If not confirmed, please fully explain and provide a summary of all assets that are not required for utility service.

1063. ATCO Electric confirmed this in its response.[378]

1064. In Section 3 of the business case for the Drumheller service building included in the application,[379] ATCO Electric stated that the current services in Drumheller include an administration office building located at a corner intersecting two major highways; and a warehouse/service centre that was built in 1985 and is located on 14.391 acres of land. The 14.391 acres of land were therefore added to rate base quite a number of years ago. During questioning at the oral hearing, Mr. Babyn, a witness for ATCO Electric, provided the following information with respect to the 14.391 acres of land:

> Q. Under the heading "Project Scope," there's a paragraph, and then there's a bullet point. That bullet point says: "Partial excavate, clearing, and site development of existing site beyond the fence line." Am I right in understanding or inferring from that that the fence line doesn't follow the property line?
> A. MR. BABYN: So what we have at the existing warehouse site in Drumheller is about -- I think there's about 14 acres of land there. We currently have flattened about seven acres that we use there for the warehouse

[377] *ATCO Gas and Pipelines Ltd. v. Alberta Utilities Commission*, 2009 ABCA 246 at paragraph 54.
[378] Exhibit 51.01.
[379] Exhibit 1, application, Business Case 85816.

> facility and the yard space that we have. So this partial excavation is referring to the other seven acres that are essentially hills that we would then knock down to allow for the development of the project we have identified in this business case.[380]

1065. Based on the information provided by Mr. Babyn, that the remaining seven acres are essentially hills, the Commission finds that it is doubtful that these remaining seven acres were ever used in the provision of utility service. This is further evidenced by the fact that, in the current application, ATCO Electric is forecasting to knock down these hills to allow for the development of the Drumheller service building project. This question of whether these remaining seven acres of land were ever used in the provision of utility service also casts doubt on the confirmation ATCO Electric provided in its response to information request UCA-AE-030(a), and adds legitimacy to the UCA's concern with the effectiveness of ATCO Electric's asset assessment.

1066. It not clear at this stage how much of the remaining seven acres will be used in the development of the Drumheller service building project. Mr. Babyn commented on this during the oral hearing as follows:

> Q. Okay. How much of the remaining site do you expect to clear, of the remaining warehouse site do you expect to clear?
> A. MR. BABYN: I think about five out of the potential seven acres is what we would clear initially. But, you know, once we get our final design and we look at all of the issues related to the large equipment that will be operating in the site and our need for additional material storage, then we'll make that final decision. But it's between the five and the seven. It's just kind of an awkward-shaped lot, so we're going to have to kind of look at that a little bit closer. But right now five to seven acres of the seven remaining.[381]

1067. Based on the response provided, it appears that ATCO Electric is relatively certain that it will use five acres of the remaining seven but it is unsure about the other two. The Commission finds that, although this land was previously included in rate base, it is not certain that the entire amount of the land is being used for the provision of utility service.

1068. While the Commission acknowledges that the amount of land and the associated cost is not material to the overall revenue requirements being applied for, it is important for ATCO Electric to make sure that all assets that are included in rate base are required for utility purposes. It appears from the testimony provided by the ATCO Electric witness that only five acres of the remaining seven acres will be used, although there is uncertainty about this. The Commission directs ATCO Electric, in the compliance filing, to provide an update with respect to the remaining seven acres of land at the Drumheller service building project site, and remove any land that is not going to be used in the provision of utility service in either 2013 or 2014. The

[380] Transcript, Volume 1, page 126, lines 19-25; page 127, lines 1-8.
[381] Transcript, Volume 1, page 131, lines 2-14.

Commission further directs that for any land removed, the resulting revenue requirement reduction include return, property taxes and any other areas that are directly impacted.

1069. With respect to the current administrative building located in Drumheller and its use once the new two story administrative and technical building is built at the warehouse site, Mr. Babyn stated that it will continue to be used until the new building is in service in 2014, at which time the continued use will be assessed.[382] Considering the uncertainty of the future use of the current administrative building in Drumheller, the Commission directs ATCO Electric, in its next GTA, to include an update on the status of the current administrative building in Drumheller and how, if it is included in rate base in the next GTA, such a facility is being used in the provision of transmission utility service.

1070. The Commission finds that the overall issue relating to the identification of assets that are no longer required to provide utility service, is currently being explored by the Commission in Proceeding ID No. 20, the Utility Asset Disposition proceeding. While the UCA stated that its recommendation about the Commission directing ATCO Electric to refine its current processes in this area will undoubtedly be affected by Proceeding ID No. 20, the UCA submitted that this recommendation be put in place now, rather than only taking steps following Proceeding ID No. 20. Based on the fact that the record of Proceeding ID No. 20 closed on August 28, 2013, with the submission of supplemental reply argument, the Commission's decision on Proceeding ID No. 20 should be issued before the end of 2013. Considering this timing, ATCO Electric will be able to incorporate any Commission directions from the decision on Proceeding ID No. 20 regarding the identification of assets no longer used for the provision of utility service, into the preparation of its next transmission GTA. Consequently, the Commission rejects the UCA's request in this proceeding that ATCO Electric refine its current processes to identify facility components that can be removed from rate base on an ongoing basis, and in a fashion that can be readily tracked and tested.

18.4 Farms, irrigation operating costs

1071. Farm transmission costs, in respect of the owner of an electric distribution system, are defined in Section 1(1)(t) of the *Electric Utilities Act* as follows:

> (t) "farm transmission costs", in respect of an owner of an electric distribution system, means
>
> (i) the proportion of the owner's costs of supplying electricity on 25 000 volt lines to the service area boundaries of rural electrification associations that the total electricity supplied to rural electrification association members within those boundaries for farm and farm irrigation purposes bears to the total electricity supplied on those lines, and
>
> (ii) an equivalent dollar amount per unit of electricity supplied by the electric distribution system to farm and farm irrigation customers who are not members of rural electrification associations;

[382] Transcript, Volume 1, page 130, lines 16-25; page 131, line 1.

1072. Section 32(c) of the *Electric Utilities Act* also states the following with respect to farm transmission costs.

> **32** The Independent System Operator must
> ….
> (c) pay farm transmission costs;

1073. ATCO Electric's practice has been to remove these farm transmission costs from its distribution function revenue requirement and include them under its transmission function revenue requirement, because the ISO pays all the revenue requirement of ATCO Electric's transmission function.

Commission findings

1074. Prior to the adoption of PBR for ATCO Electric's distribution function, when ATCO Electric filed joint distribution and transmission Phase I revenue requirement applications, it was easy to verify that the amounts included for farm transmission costs in the transmission revenue requirements were the same as the amounts removed from the distribution revenue requirement. With the adoption of PBR and the fact that joint transmission and distribution applications will not be filed, the Commission is no longer able to make such verification.

1075. There is no direction with respect to this area for ATCO Electric in Decision 2012-237 on PBR. None of the parties raised any objections to the inclusion of the farm transmission costs in this application, and no parties objected to any of the forecast transmission costs included in the application. From a practical perspective it is more efficient for ATCO Electric to continue to include the farm transmission costs in the transmission GTAs, instead of having the distribution function submit a separate application for these.

1076. ATCO Electric submitted details of the calculations of the farm transmission costs for 2013 and 2014 in response to information request AUC-AE-016.[383] The revenue requirement amounts for 2013 and 2014 are $3.7 million and $4.1 million respectively. The main reason for the increase in the total farm transmission costs between 2012 and 2013, and 2013 and 2014, is due to the return and depreciation associated with the forecast increase in mid-year rate base. The mechanical calculations have been made correctly. On this basis, the Commission considers the forecast to be reasonable, and approves the forecast farm transmission costs of $3.7 million for 2013 and $4.1 million for 2014. The Commission directs ATCO Electric to reflect these approved farm transmission costs for 2013 and 2014, as detailed in the response to information request AUC-AE-016, in the compliance filing.

18.5 Minimum filing requirements

1077. The RPG submitted that MFR are fundamental to an efficient regulatory process because it ensures that essential information necessary for the review and testing of applications is placed on the record. It further submitted that when this information is not provided as part of the application, interveners are forced to use information requests to solicit primary information and lose the opportunity to scrutinize it, and it argued that this is prejudicial to the Commission and interveners, and can be remedied by expanding the MFR.

[383] Exhibit 50.01.

1078. As detailed in paragraphs 1079 to 1092 below, the RPG provided the following comments on certain aspects of the MFR.

Direct assigned project information should be provided separately for each project that will be or has been the subject of a facility application

1079. With respect to certain capital projects included by ATCO Electric in Schedule 10-4 of the application, there were cases where the grouping of projects was presented as a single project. Packaging various single projects together, when these individual projects will or do have a permit and license, obscures the record and impairs the proper testing of the application.

Project milestone schedules and expenditure profiles should be provided for each direct assigned capital project

1080. The project milestones and timing of expenditures information, provided by ATCO Electric subsequent to the filing of the application, was beneficial and constructively assisted in understanding the direct assigned capital projects expenditures forecast. The RPG recommended that similar information be required as part of a tariff or deferral account application, with the added requirement that capital expenditure profiles be provided on a monthly or quarterly basis, covering the entire life of the project.

AESO change order requests and authorizations should be provided for each direct assigned capital project

1081. The AESO change order requests and authorizations filed by ATCO Electric provided useful insight in to the development of the projects and the reasons for any changes. The RPG recommended that ATCO Electric be required to file similar documents with its application, and any omissions and updates filings.

Direct assigned capital project cost estimation reports, using an expanded template to include each major cost component, should be provided for each major development milestone

1082. It is useful to the understanding of the underlying cost drivers, and therefore reasonableness or prudence, to review the cost estimates for capital projects at various stages of the project. GTA applications should include cost estimates at the following stages:

- PPS
- NID
- facility application
- most current version at the time of the application
- final cost report if available

1083. The cost category information currently required by the AESO should be expanded. The RPG recommended that at a minimum, transmission lines and substation facilities direct material and construction labour costs should be sub-divided into the following categories:

- site preparation (clearing & access)
- foundations

- structures (assembly, erection & stringing)

1084. The more detailed categories used by ATCO Electric would also be acceptable, and these categories are as follows:

- clearing
- foundations
- tower assembly
- tower erection
- stringing

Direct assigned capital project reporting estimates should provide detailed engineering

1085. Engineering costs should be reported separately as a single line item in the cost estimates, with a further breakdown into preliminary engineering and detailed engineering.

Transmission facility owners' should submit a schedule of project attributes for both transmission lines and substations, as part of a tariff or deferral account application

1086. In information request IPCAA-AE-008(c) ATCO Electric was requested to provide the following information:

> (c) In a functioning Excel spreadsheet, please provide for all transmission line projects (or subprojects) in the 2010 to 2014 time frame in excess of $5 million in cost the following:
>
> > i. identify the standard tower design, the percentage of towers that are not tangent structures, the type of foundation(s) (identified in percentage terms if more than one is used), the km length of the lines, the voltage levels, the line loading capacity, the percentage of the transmission line that is on crown land, conductor size, conductor bundling, whether summer or winter construction, and any unusual challenges relative to the terrain (muskeg, winter construction only, mountainous, etc.)
> >
> > ii. calculate the cost for each of the transmission line component of these projects in dollars per km and dollars per km per MVA, providing a separate cost for (1) materials, (2) labour, (3) other costs and (4) total costs, and provide all details supporting the calculations.

1087. The information provided by ATCO Electric in response to this information request was beneficial and instructive in understanding the nature of the various projects. The RPG recommended that the TFOs submit such information, for both transmission line projects and substation projects, as part of a tariff or deferral account application.

Transmission facility owners' should provide parametric estimation details

1088. As described by ATCO Electric in the application, ATCO Electric uses parametric estimating techniques during the feasibility phase of a capital project. The RPG submitted that

the parametric values that are derived through this process would be of assistance in evaluating the reasonableness of costs, when combined with the full disclosure of project attributes.

Current functional specifications

1089. The filing of the AESO functional specifications for all direct assigned capital projects would assist in understanding the nature of these projects and the requirements requested of ATCO Electric by the AESO. The RPG submitted that each TFO should be required to file the most up-to-date functional specification for each direct assigned capital project, as part of its tariff or deferral account application.

Bulk line optimization studies

1090. Section 12(1)(c) of ISO Rule 502.2 requires a TFO to perform a bulk transmission line optimization study for all lines greater than 10 km. Section 12(1)(d) of the same rule requires a TFO to perform a bulk transmission line optimization study for a new 240-kV or higher line with a total length of 50 km or greater. The RPG submitted that such bulk transmission line optimization studies be provided, to determine if ATCO Electric is designing transmission lines with the objective to reduce the overall costs.

1091. The following additional information should also be included in the MFR:

- ATCO Electric's comprehensive business cases
- ATCO Electric's post completion reports
- ATCO Electric's 60-day and 150-day reports that are filed in response to ISO rules

1092. The RPG submitted that it extensively used the information such as functional specifications, AESO monthly progress reports, and disaggregated transmission and substation costs, in compiling its evidence. It submitted that, since the documents being requested are existing documents, and the cost to create these documents is charged to ratepayers, access should not be denied to those who ultimately pay for it, and the extra cost of providing this information is minimal given modern technology.

Commission findings

1093. For the sake of completeness and transparency, all separately identifiable capital projects, even when they are part of an overall larger project, should be shown on the schedule of capital expenditures; this will enable parties to examine the complete nature of the overall larger project on a more detailed level. The Commission directs ATCO Electric, in all future GTAs, to provide details of each capital project on an individual basis, on the schedule of capital expenditures.

1094. By including more information in the application, the submission of which ATCO Electric controls, it could save a lot of work for all parties involved once the application is submitted. The intervener groups focused a lot of attention during this proceeding on the examination of the forecast capital projects, the majority of which are part of the direct assigned capital projects area, and will be included in future deferral account applications. The additional information the RPG is requesting would be beneficial in understanding the scope of the projects, the cost estimates included, the supporting reasons behind the design specifications, as well as the involvement of the AESO. ATCO Electric did not argue why it was not necessary to provide the additional information. However, there should be a minimum threshold beyond

which this information is required to be provided. In information request IPCAA-AE-008(c) IPCAA requested information for each capital project in excess of $5.0 million. The Commission finds that this is an acceptable threshold.

1095. While the Commission finds that the additional information should be included, it is not prepared to revise the MFR to make the provision mandatory for all transmission utilities. The MFR is in place not only for ATCO Electric, but for all the other transmission utilities, and it may not be necessary for the other transmission utilities to provide the level of detail requested by the RPG with respect to capital project costs, especially if the level of capital project activity for these other transmission utilities is not significant. Consequently any proposed changes to the MFR should be examined through a separate process, in which all interested parties would be able to participate. The Commission therefore rejects the submission of the RPG that the information it has requested be made part of the MFR.

1096. The Commission directs ATCO Electric, in its next transmission GTA and next annual transmission deferral account application, to include the following additional information with respect to any individual direct assigned capital project that has a forecast capital cost in excess of $5.0 million:

- project milestone schedules and the timing of capital expenditures
- AESO change order requests and authorizations
- cost estimates at the stages described in paragraph 1082 of this decision
- cost estimates by the categories described in paragraph 1084 of this decision
- the preliminary engineering costs included in the cost estimates
- the detailed engineering costs included in the cost estimates
- schedules of project attributes, for both transmission line projects and substation projects, similar to the information provided in response to information request IPCAA-AE-008(c)
- parametric values that are derived through the use of parametric estimating techniques
- the current AESO functional specifications
- bulk transmission line optimization studies where required by ISO Rule 502.2
- post completion reports
- 60-day and 150-day reports that are filed in response to the AESO's rules

19 Order

1097. It is hereby ordered that:

(1) ATCO Electric Ltd. will submit a compliance filing to the Alberta Utilities Commission by no later than 4 p.m. on October 22, 2013.

Dated on September 24, 2013.

The Alberta Utilities Commission

(original signed by)

Anne Michaud
Panel Chair

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd. (AE) L. Keough D. Sheehan B. Yee J. Grattan D. DeChamplain C. Kostyk S. Ambeault L. Kerckhof L. Kizuk D. Hoshowski D. Freedman D. Wilson
Alberta Direct Connect Consumers Association (ADC) R. Secord C. Chekerda J. Dauphinais M. Gorman G. Meyer
AltaLink Management Ltd. (AML) R. Pallister D. Madsen N. Burns
Consumers' Coalition of Alberta (CCA) J. A. Wachowich A. P. Merani R. Retnanandan
EPCOR Distribution & Transmission Inc. (EDTI) P. Laderoute
ENMAX Power Corporation (EPC) J. Schlauch K. Hildebrandt T. Carle
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster V. Bellissimo J. Cheng R. Mikkelsen
Independent System Operator (ISO) J. Martin R. Sharma N. Weigel

Name of organization (abbreviation) counsel or representative
Office of the Utilities Consumer Advocate (UCA) M. Keen R. B. Wallace, QC B. Shymanski R. Bell

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
ATCO Electric Ltd. (AE) L. Keough D. Sheehan	General Panel R. Lambright C. Clark J. Babyn B. McNabb Direct Assigned Capital Panel D. DeChamplain R. Boven P. Goguen C. Kostyk Confidential Module D. DeChamplain R. Boven P. Goguen C. Kostyk
Alberta Direct Connect Consumers Association (ADC) R. Secord I. Okoye	C. Chekerda J. Dauphinais M. Gorman G. Meyer R. Albers
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	
Ratepayer Group (RPG) (consisting of ADC, CCA, and IPCAA) M. Forster R. Secord I. Okoye J. A. Wachowich	General Panel D. Levson V. Bellissimo R. Belland T. Cline T. Mohr Confidential Module T. Mohr
Office of the Utilities Consumer Advocate (UCA) M. Keen B. Wallace	R. Bell

The Alberta Utilities Commission

Commission Panel
A. Michaud, Panel Chair
M. Kolesar, Vice-Chair
B. Lyttle, Commission Member

Commission Staff
C. Wall (Commission counsel)
D. Mitchell
S. Allen
L. Mullen
C. Pham

Appendix 3 – Summary of Commission directions

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

1. The Commission finds the material included in the revenue requirement supporting schedules in Exhibit 188.02 to be helpful and necessary to assist in validating the accuracy of the revenue requirement calculations. This material should have been provided as part of the omissions and updates filing to support the revised revenue requirements, just as the revenue requirements included in the initial application were supported by the information in Exhibit 3. The Commission directs ATCO Electric, in any future general tariff applications (GTA) where an omissions and updates filing is submitted, to include all detailed supporting revenue requirement schedules, as part of the omissions and updates filing, in Microsoft Excel format with all links and cross references intact. ..... Paragraph 13

2. The Commission finds the information provided by ATCO Electric in Attachment 5 of Section 31 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 33 of Decision 2011-134. The Commission directs ATCO Electric, in its next GTA, to file applied-for, actual and approved amounts for the years 2005 through to and including the relevant test years as part of the application. ..... Paragraph 19

3. The Commission finds that the information provided by ATCO Electric in Attachment 2 of Section 5 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 343 of Decision 2011-134. The Commission directs ATCO Electric to update the information in Attachment 2 of Section 5, if necessary, to reflect the final forecast amounts for 2013 and 2014 that are included in the compliance filing. The Commission reminds ATCO Electric that the direction included in paragraph 343 of Decision 2011-134 has no end date so ATCO Electric is still bound by this direction with respect to future applications. ..... Paragraph 23

4. In the application, ATCO Electric requested placeholder treatment for its terms and conditions of service. During the oral hearing, Commission counsel questioned ATCO Electric on why it had requested placeholder treatment for the terms and conditions of service, as evidenced by line 20 of Attachment 3 of Section 1 of the application. In an undertaking response, ATCO Electric clarified that it was not seeking placeholder status for its terms and conditions of service as part of this application, and that it would remove the reference from Attachment 3 of Section 1 of the application in the compliance filing. The Commission therefore directs ATCO Electric, as part of the compliance filing, to file an updated Attachment 3 from Section 1 of the application, in which any reference to a placeholder for its terms and conditions of service is excluded. ..... Paragraph 26

5. The Commission also finds that VPP payouts for employees who work on non-direct assigned capital projects should also be charged to the capital projects they work on. As a result, the Commission directs ATCO Electric, in the compliance filing, to include forecast VPP amounts for 2013 and 2014 for employees who work predominantly on non-direct assigned capital projects, as part of the forecast capital expenditures for these

projects; and to remove these amounts from whatever expense category they were included under in the application. ..... Paragraph 68

6. ATCO Electric has not included any such AESO Rider I credit defaults in the 2013 revenue requirement or the 2014 revenue requirement and there has been no associated placeholder amount identified in revenue requirements over the test period. It is therefore unnecessary to establish a deferral account during this test period. The Commission therefore denies ATCO Electric's request to establish a deferral account for AESO Rider I credit default risk. The Commission directs ATCO Electric, in the compliance filing, as part of the updated Section 1, Attachment 3 schedule to be submitted, to remove the AESO Rider I credit risk deferral. ..... Paragraph 88

7. The Commission directs ATCO Electric, in the compliance filing, as part of the updated Section 1, Attachment 3 schedule to be submitted, to do the following:

   - remove the placeholder amount for the provincial FIT rates for 2013 and 2014
   - include placeholder amounts for the provincial forecast of income tax deductible capital costs for 2013 and 2014
   - include placeholder amounts for the provincial deduction of deferrals for income tax purposes for 2013 and 2014 ..... Paragraph 96

8. Therefore, the Commission directs ATCO Electric, as part of the compliance filing, to submit the details of the actuarial pension plan valuation that was scheduled to be completed as of December 31, 2012, and to include the resulting impact on the defined benefit pension plan costs for 2013 and 2014 that were included in the application. These impacts should not be reflected in the revenue requirements included in the compliance filing. ..... Paragraph 101

9. Any requested dollar amounts for such flow-throughs that are made by ATCO Electric relating to the 2013 and 2014 transmission tariffs would still have to be reviewed and approved by the Commission for accuracy and relevance. The Commission directs ATCO Electric, in the compliance filing, to include the approval for this continuation, on the updated Section 1, Attachment 3 schedule to be submitted. ..... Paragraph 110

10. The Commission considers that these errors may have been discovered and corrected earlier had the detailed calculations used to derive the depreciation expense/amortization and capital cost allowance placeholder amounts on the revised Section 1, Attachment 3.1 schedule been provided as part of the omissions and updates filing. For the purposes of verifying the calculation of the direct assigned capital projects deferral accounts for 2013 and 2014 in future years (the establishment of such deferral account being approved earlier in Section 5.1.4 of this decision), it would be beneficial to have the detailed calculations related to the forecast amounts. The Commission therefore directs ATCO Electric, in the compliance filing, to include details of the calculations used to derive the depreciation expense/amortization and capital cost allowance placeholder amounts that are included on the updated Section 1, Attachment 3.1 schedule that will be submitted as part of the compliance filing. These details should include the relevant capital asset categories and applicable depreciation rates, as well as the relevant capital cost allowance classes and applicable capital cost allowance rates. ..... Paragraph 116

11. To clarify this situation, the Commission directs ATCO Electric, in the compliance filing, to remove the dollar amounts for the ATCO I-Tek placeholders from the Section 1,

Attachment 3 schedule that is submitted as part of the compliance filing; and further directs ATCO Electric to include a note to the "IT Placeholders" area of the Section 1, Attachment 3 schedule that is submitted as part of the compliance filing, which explains that the ATCO I-Tek rates only are subject to placeholder treatment. ..... Paragraph 120

12. In reviewing the information contained in schedules 30-13 and 30-14 of the application (and the updated schedules 30-13 and 30-14 of the omissions and updates filing) the Commission finds that, while the forecast ATCO I-Tek charges included under the GTA category "Transmission" are entirely for the transmission function, the amounts included under the "Isolated," "General," "Common" and "Corporate" categories of these schedules are the total amounts before allocation. The Commission considers that, in order to aid in the true-up of the ATCO I-Tek rates placeholders for the transmission function, it is important to know how much of the forecast dollar amounts in schedules 30-13 and 30-14 is for transmission only. In order to do this, the information in schedules 30-13 and 30-14 should be supplemented with additional schedules that show the forecast ATCO I-Tek units and resulting dollars for ATCO Electric's transmission function only. Therefore, the Commission directs ATCO Electric, in the compliance filing, to include schedules 30-13 and 30-14, updated to reflect all of the directions in this decision; and also directs ATCO Electric, in the compliance filing, to include supplementary schedules in the format of schedules 30-13 and 30-14 that includes only the units and dollars reflected in the compliance filing that are applicable to its transmission function. ..... Paragraph 122

13. The Commission considers that, pursuant to Decisions 2013-111 and 2013-293, the issue of the allocation of corporate costs for the years 2013 and 2014 is resolved. Consequently, the Commission finds that there is no need for a placeholder for these costs as ATCO Electric requested. The Commission therefore denies the request of ATCO Electric for a placeholder for corporate costs. The Commission directs ATCO Electric, in the compliance filing, to remove corporate costs from the Section 1, Attachment 3 schedule that will be included as part of the compliance filing. ..... Paragraph 132

14. In the compliance filing, the Commission directs ATCO Electric to recalculate and resubmit schedules 25-8 and 25-9. The Commission further directs that separate schedules 25-8 be prepared for each of 2013 and 2014. The Commission directs the following with respect to the Schedule 25-8 for 2013 that will be submitted as part of the compliance filing:

- The schedule is to be updated to remove the 2012 forecast amounts included in the application and include the 2012 approved amount from Decision 2013-293, which is $42.4 million.
- The schedule is to include the 2013 forecast amounts that result from applying inflation of 2.2 per cent to the 2012 approved amounts from Decision 2013-293 for the corporate office - supplies and corporate office - office rent functions; and applying inflation of 3.5 per cent to the 2012 approved amounts from Decision 2013-293 for all other functions.
- The schedule is to be updated to use the allocation methodology approved in Decision 2013-111, including the causal allocations of the internal audit function and the human resources function.

- The schedule is to be prepared using the actual audit hours for the years 2009, 2010 and 2011 in calculating the allocation of the internal audit function costs.
- The schedule is to be prepared using the actual headcount information at December 31, 2011, in calculating the allocation of the human resources function costs.
- The schedule is to be prepared using the actual results from the year 2011 as inputs in the allocation formula, including the December 31, 2011, results of ATCO Gas Australia.
- The schedule is to include details of how the allocation percentages for the General, CU Public and CU Inc. Public categories were arrived at.
- The schedule is to include details of how the internal audit function and human resource function allocations were arrived at. ..... Paragraph 135

15. The Commission directs the following with respect to the Schedule 25-8 for 2014 that will be submitted as part of the compliance filing:

- The schedule is to be updated to remove the 2012 forecast amounts included in the application and include the 2012 approved amounts from Decision 2013-293, which total $42.4 million.
- The schedule is to include the 2014 forecast amounts that result from applying inflation of 2.1 per cent to the 2013 forecast amounts for the corporate office - supplies and corporate office - office rent functions; and applying inflation of 3.5 per cent to the 2013 forecast amounts for all other functions.
- The schedule is to be updated to use the allocation methodology approved in Decision 2013-111, including the causal allocations of the internal audit function and the human resources function.
- The schedule is to be prepared using the actual audit hours for the years 2009, 2010 and 2011 in calculating the allocation of the internal audit function costs.
- The schedule is to be prepared using the actual headcount information at December 31, 2011, in calculating the allocation of the human resources function costs.
- The schedule is to be prepared using the actual results from the year 2011 as inputs in the allocation formula, including the December 31, 2011, results of ATCO Gas Australia.
- The schedule is to include details of how the allocation percentages for the General, CU Public and CU Inc. Public categories were arrived at.
- The schedule is to include details of how the internal audit function and human resource function allocations were arrived at. ..... Paragraph 136

16. The Commission directs the following with respect to the Schedule 25-9 that will be submitted as part of the compliance filing:

- The amounts with respect to 2010 and 2011 are to be removed from the schedule.

- The schedule is to include the amounts for 2012, 2013 and 2014 on a functional basis for the total corporate costs to be allocated to the entire ATCO Ltd. group of companies, separated out among General, CU Public, and CU Inc. Public.
- The schedule is to include the amounts for 2012, 2013 and 2014 on a functional basis for only the corporate costs that are allocated to ATCO Electric, separated out among General, CU Public, and CU Inc. Public. ..... Paragraph 137

17. The 2013 and 2014 forecast amounts for allocated corporate costs for ATCO Electric's transmission function that are to be included in the compliance filing will be based on the amounts resulting from the directions included in paragraphs 135, 136 and 137 of this decision. The amount to be allocated to the transmission function will be calculated by using the Commission-approved cost allocations for corporate administration and general costs between transmission and distribution. These approved cost allocations are discussed in Section 13.1 of this decision. The Commission directs that, in the compliance filing, ATCO Electric use the applicable approved cost allocations for corporate administration and general costs from Section 13.1 of this decision in calculating the transmission function's corporate costs for 2013 and 2014. The Commission further directs that details of how the allocated corporate costs for the transmission function were calculated be included as part of the compliance filing. ..... Paragraph 138

18. The Commission has re-initiated Proceeding ID No. 20 regarding the issue of utility asset dispositions and stranded assets. The Commission has also initiated Proceeding ID No. 2191 regarding the generic cost of capital for 2013. The Commission considers that the outcome of these proceedings may impact both the common equity ratio and the return on equity percentage for ATCO Electric's transmission function for 2013 and/or 2014. Therefore the Commission grants the request by ATCO Electric that the common equity ratio of 37 per cent and the return on equity percentage of 8.75 per cent be treated as placeholders for 2013 and 2014. The Commission directs ATCO Electric, in the compliance filing, to use 8.75 per cent as the return on equity percentage for 2013 and 2014, and to use 37 per cent as the common equity ratio for 2013 and 2014. ..... Paragraph 143

19. It would be convenient to have an updated placeholder summary schedule that reflects all of the applicable directions that have been made in this decision. The Commission therefore directs ATCO Electric, as part of the compliance filing, to file an updated Attachment 3 schedule and an updated Attachment 3.1 schedule from Section 1 of the application, that reflects and incorporates the applicable directions contained in this decision. ..... Paragraph 144

20. However, it is a fact that an IASB project on rate-regulated activities is currently in progress, and it would be helpful to have more information in assessing the CCA's request for a deferral account for IFRS. Therefore, in the compliance filing, the Commission directs ATCO Electric to provide a status update and a summary of the activities that have occurred since September, 2012 on the IASB's rate-regulated project, including information regarding any interim standards, exposure drafts or discussion papers. The Commission will make a finding regarding the CCA's request for a deferral account for IFRS in its subsequent decision on ATCO Electric's compliance filing. ..... Paragraph 156

21. While the four per cent inflation rate for contractors is greater than the 3.5 per cent labour inflation rate in each of 2013 and 2014 approved by the Commission in Section 5.4.1.1 of this decision, the Commission has increased the inflation rate in recognition that contractor labour rates can be more volatile and sensitive to labour market supply and demand than the more expansive pool of full time labour personnel. The Commission directs ATCO Electric, in the compliance filing, to use an inflation rate of four per cent in each of 2013 and 2014 for contractor labour for contractors who work on projects other than direct assigned capital projects. ..... Paragraph 185

22. Further, an escalation factor is unnecessary because direct assigned capital projects are already subject to deferral account treatment. The Commission consequently denies ATCO Electric's request for a 25 per cent contractor escalation factor for its direct assigned capital projects and directs ATCO Electric to reflect this finding in the compliance filing. ..... Paragraph 205

23. Based on the information included in Table 3 of this decision, the Commission agrees with the ADC that the actual annual fuel costs over the period 2009 to 2011 is approximately $6.3 million, and that the latest forecast of fuel costs for 2012 is also $6.3 million. This is despite the approved annual forecast amounts for this period ranging from $8.3 million for 2011 to $9.6 million for 2010. The Commission has included some variance analysis around the $6.3 million amount for each of 2013 and 2014 in paragraph 43 of this decision. Based on the actual fuel cost levels for the years 2009 to 2012, ATCO Electric's history over the last four years of over-forecasting the fuel costs, as well as the variance analysis included in paragraph 43 of this decision, the Commission finds that a reasonable forecast for the years 2013 and 2014 would be $6.3 million for each year and directs ATCO Electric, in the compliance filing, to include fuel costs of $6.3 million for 2013 and $6.3 million for 2014. ..... Paragraph 243

24. On this basis, the Commission rejects the CCA's recommendation that ATCO Electric provide, in its next GTA, an assessment of whether its health and safety standards and practices, and associated costs, are similar to those of the other TFOs. While the overall costs incurred for safety are difficult to quantify, the Commission directs ATCO Electric, in its next GTA, to identify any specific incremental costs that are included for safety, and to make sure these incremental costs are justified. ..... Paragraph 260

25. The Commission directs ATCO Electric to provide, in its next GTA, an estimate of the costs and benefits associated with corrective and emergency maintenance procedures, to support its forecast labour and non-labour costs. It also directs ATCO Electric, as part of its next transmission GTA, to include information on how it evaluates all of the costs associated with its maintenance activities, as it explained in the quote in paragraph 281 of this decision. ..... Paragraph 284

26. Based on this uncertainty about the number of employees actually signed up for the program and the difficulties associated with retaining transmission line crew members, the forecast assumptions of signing up 32 employees in 2012 and retaining them all over the ensuing 24-month period are overly optimistic and therefore not reasonable. The Commission finds that the forecast cost of this program should be reduced by 10 per cent and directs ATCO Electric to reflect this 10 per cent reduction in the compliance filing. This reduction is to be allocated 50 per cent to O&M Account 563/569 and 50 per cent to capital. ..... Paragraph 301

27. The Commission is interested in how successful this program will be and directs ATCO Electric, in its next GTA, to include an update on the status of this incentive allowance program. Such an update should include, but not be limited to, information on how many of the forecast 32 crew members actually signed up for the program in late 2012, how many forfeited the allowance by leaving before the 24-month period, and how many are still eligible for the incentive allowance payment. ATCO Electric should also indicate whether it intends to continue and/or vary the program as part of its next GTA. ..... Paragraph 302

28. Because of the uncertainty of the reasons for the increase in 2013 and 2014 with respect to the whole area of maintenance of offices, warehouses, and yards, ATCO Electric has not explained clearly why the costs are increasing; hence the Commission has no basis upon which to assess the reasonableness of the entirety of the forecast requested. The recommendation by the CCA for a $0.2 million reduction in the transmission function's share of general O&M is a reasonable request, considering the level of uncertainty. Therefore, the Commission directs ATCO Electric, in the compliance filing, to reduce the transmission function's allocated share of general O&M costs in 2013 and 2014 by $0.2 million in each year. The Commission considers this is reasonable in light of the $9.94 figure amount provided by LCVM. Using the square footage information provided in Table 15 of this decision of 157,639 and 175,907 for 2013 and 2014 respectively, and applying the $9.94 amount to them, results in figures of approximately $1.57 million for 2013, and $1.75 million for 2014. Comparing these figures to the ones in Table 15 results in a difference of $0.18 million for 2013 and $0.2 million for 2014. ..... Paragraph 324

29. In response to a Commission question about the supporting revenue requirement schedules that were submitted in conjunction with the omissions and updates filing, ATCO Electric advised that Schedule 25-4 of the supporting revenue requirement schedules had not been updated. It is important to have a full and complete set of supporting schedules in which all the cross referenced figures agree. Accordingly, the Commission directs ATCO Electric, in the compliance filing, to submit a full and complete set of supporting revenue requirement schedules that reflect all of the findings and directions in this decision. ..... Paragraph 325

30. The Commission agrees that ATCO Electric's forecast depreciation rates for 2013 and 2014 are reasonable and fully supported and are therefore approved as filed. The Commission directs ATCO Electric, in the compliance filing, 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 332

31. However, parties would benefit from ATCO Electric preparing an update to the annual provision for true-up, and the Commission consequently directs ATCO Electric to prepare such an update at the time of its next depreciation study. ..... Paragraph 334

32. In response to a Commission question about the supporting revenue requirement schedules that were submitted in conjunction with the omissions and updates filing, ATCO Electric advised that the depreciation amount for 2013 for direct general property, plant and equipment on line nine of Schedule 6-2 should agree with the cross reference in Schedule 6 6. In the same response, ATCO Electric stated that it would incorporate this update in the compliance filing. It is important to have a full and complete set of supporting schedules in which all the cross referenced figures agree. In paragraph 325 of this decision, the Commission directed ATCO Electric to submit a full and complete set

of supporting revenue requirement schedules; it further directs that all cross references in those supporting revenue requirement schedules agree, including the one discussed in this paragraph. ..... Paragraph 335

33. With respect to the Steen River Unit CUL 441, the retirement date included in the response to information request AUC-AE-019(a) is 2032; however, the retirement date included in the supporting revenue requirement schedules is 2031. It is important to know the correct retirement date for this unit. Therefore, the Commission directs ATCO Electric, as part of the compliance filing, to provide the correct retirement date for Steen River Unit CUL 441 and to include the correct retirement date in Schedule 6-5 in the compliance filing. ..... Paragraph 337

34. The Commission finds that the income tax rates used in the preparation of the application are the substantively enacted rates and therefore approves them as filed. In Section 5.1.8 of this decision, the Commission also made findings with respect to the deferral account for income taxes. The Commission directs ATCO Electric, in the compliance filing, to update the income tax expense calculations for 2013 and 2014 where necessary to reflect the findings and directions made by the Commission in all other areas of this decision. ..... Paragraph 344

35. With respect to the "SOP Revenue" and the "Other Revenue" categories, the 2010 actuals included in the response to the information requests CCA-AE-024(b) and UCA-AE-029(d) are $0.5 million and $0.3 million respectively. The 2010 actuals for these categories in Schedule 8-1 included in the supporting revenue requirement schedules are $0.3 million and $0.5 million respectively. For the sake of accuracy and completeness, it is important to reflect the correct actuals for 2010 for these categories. Therefore, the Commission directs ATCO Electric to provide in the compliance filing, the correct 2010 actuals for the "SOP Revenue" and "Other Revenue" categories and to include these correct amounts in Schedule 8-1 in the compliance filing. ..... Paragraph 347

36. The Commission directs ATCO Electric, as part of its next GTA, to provide an update on the expected future use of the Vegreville land, but otherwise approves these 2011 rate base additions as filed, subject to any future adjustments that may arise as a result of the true-up of any placeholders. ..... Paragraph 409

37. As the release date of this decision is well after the end of 2012, the Commission finds it necessary for ATCO Electric to update the calculation of the mid-year net rate base forecast for 2012, included in the omissions and updates filing, to reflect the actual results for 2012, and directs ATCO Electric to provide such an update in the compliance filing. This update will allow the actual capital project results for 2012 to be incorporated and factored into the calculation of the revenue requirements for the years 2013 and 2014. ..... Paragraph 410

38. In Section 11.3 of the decision, the Commission considered a similar request from the RPG to coordinate with the AESO in respect of direct assigned capital projects. Recognizing that the AESO is legislatively responsible for system planning, the Commission nevertheless indicated support for the RPG's recommendation that TFOs and the AESO work together to prioritize and coordinate their projects on a global basis, and the Commission encouraged ATCO Electric and the AESO to do so. As ATCO Electric has indicated that it already consults with the AESO respecting the timing and need for capital maintenance projects, the Commission does not consider it necessary to further direct ATCO Electric to do what it is already doing. The Commission expects that

ATCO Electric will continue to consult with the AESO regarding its capital maintenance projects and will do so in consideration of the best interests of its customers, and with the objective of avoiding needless expense. The Commission would like further information regarding these consultations and accordingly directs ATCO Electric to provide a report, as part of its next GTA, describing the consultations that it has engaged in with the AESO regarding its capital maintenance projects and outlining the outcome of these consultations in respect of the capital maintenance projects it has proposed. ..... Paragraph 424

39. Notwithstanding, based on the information provided for this project on the record of this proceeding, the Commission is not prepared to approve this entire project which, according to ATCO Electric, is an annual program for the next 10 to 15 years. The Commission has only approved the forecast expenditures and additions for the years 2013 and 2014 for the two lines identified as requiring immediate attention. In the event that ATCO Electric intends to continue with this project as indicated for the next 10 to 15 years, ATCO Electric is directed to bring forward a substantive business case and request approval in its next GTA for the forecast expenditures and additions for this project. ..... Paragraph 444

40. Given the strain on the labour resources available to complete all of the forecast capital project work during the test period, as acknowledged by ATCO Electric throughout the proceeding, the difficulty in forecasting the completion timelines of these projects, and ATCO Electric's own assessment that there is only a medium likelihood that certain rebuilds will be completed during the test period, the Commission finds that a 25 per cent reduction to each of the forecast 2013 expenditures, 2013 additions, 2014 expenditures and 2014 additions is warranted and reasonably reflects the expected activity able to be completed during the test period. The Commission directs ATCO Electric to reflect these reductions in the compliance filing. This reduction is not to be applied to the Steep Bank substation rebuild, because the cost of this project is fully offset by a forecast customer contribution. ..... Paragraph 462

41. As mentioned in the response to information request UCA-AE-048(b), business cases for this project were also submitted as part of the 2005-2006 GTA and the 2007-2008 GTA, and forecast costs for this project have been approved since that time. With the exception of six structures on one line that has been identified as a high priority, ATCO Electric is now forecasting to work on lines that are identified as having only a moderate risk. Considering that there have been no outages since 2004 due to double circuit contacts, the Commission considers there to be reasonable doubt that there will be risks to the reliability of the system if this program does not proceed as forecast over the test period. Accordingly, the Commission finds that the line survey, which is forecast to be completed during the test period, nine years after the program started, should be completed, and that the remediation of the six structures on the one high priority line identified by ATCO Electric should be completed. The forecast costs to complete these tasks are approved, and the Commission directs ATCO Electric, in the compliance filing, to only include costs that are required to complete the line survey and to remediate the six structures on the one high priority line. ..... Paragraph 471

42. With regard to continuation of this project, once ATCO Electric completes the line survey in 2014, it is directed to submit detailed business cases in a future GTA, describing the results of the survey, and evaluating the alternative costs of remediation for any future lines. This evaluation should be done on a line by line basis, and include

the results of any prioritization assessment with respect to any lines for which remediation is recommended. The business case should detail possible alternatives which were highlighted in the original business case filed in the 2005/2006 GTA Project 50940, where on page 7 ATCO Electric said:

> Field measurements are also important in the selection of the best remedial action strategy on a section by section basis. For example, a line with a relatively small number of spans with potential problems may be mitigated differently than a line where the majority of spans have a potential clearance issue. ..... Paragraph 472

43. Given its poor history of forecasting in this area, the Commission is not persuaded by ATCO Electric that it will be able to complete the work it has forecast during the test period, particularly during a period of unprecedented capital spending. Based on the average actual under-spending in this area from the years 2008 to 2011, a period which did not include the level of capital activity that is forecast to be conducted over this test period, the Commission finds a reduction of 40 per cent in each forecast test year to be reasonable. The Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures and additions in each of 2013 and 2014, for telecommunication capital maintenance, by 40 per cent. ..... Paragraph 501

44. The Commission has previously directed in this decision that ATCO Electric update the application as part of the compliance filing to incorporate the 2012 actual capital expenditures. Therefore the reduction recommended by the RPG will be reflected in the compliance filing and no additional direction is required. The Commission directs that a $52.1 million increase in capital expenditures for 2013 be included in the compliance filing as a result of the delay in milestone payments for 2012, and this amount not be included in the calculation of the nine per cent reduction with respect to forecasting accuracy as directed in paragraph 777 of this decision. ..... Paragraph 515

45. The Commission finds that a $418.4 million reduction would not be reasonable. The RPG's calculation produced a figure of only $306.8 million. A two-month reduction would result in a reduction of $104.6 million, while a 20 per cent reduction to the total 2014 forecast expenditures of $575.3 million results in a figure of $115.1 million. Given the record of the proceeding with respect to the implementation of the EATL project, the Commission considers that a reduction of $110.0 million would be reasonable, and directs ATCO Electric, in the compliance filing, to reduce the 2014 capital expenditures for the EATL project by $110.0 million, and to eliminate the 2014 forecast capital additions for this project. ..... Paragraph 530

46. Given the evidence from ATCO Electric's witness that the forecast and budget labour numbers on the monthly progress report are not like for like, the Commission finds that ATCO Electric has not adequately explained what is included in the labour forecast amounts. The Commission is not persuaded that the forecast amount requested in the application is reasonable given the uncertainty on the record referenced above. The Commission agrees with the proposal of the RPG that the forecast labour costs for this project be reduced by $109.0 million, for the purposes of establishing the revenue requirement for the test years. The $109.0 million is roughly equivalent to the sum of the $60.0 million for escalation and the $50.0 million for contingencies provided by the ATCO Electric witness. The Commission does not consider that this $109.0 million should be applied to the 2013 opening CWIP balance, as this figure will be updated in the

compliance filing to reflect the 2012 actuals. The Commission directs ATCO Electric, in the compliance filing, to reduce the 2013 forecast capital expenditures and additions for the HRTD program by $109.0 million. ..... Paragraph 563

47. The Commission considers that a reduction to the forecast camp costs that is generally reflective of the comparable hotel costs and expected occupancy rates is warranted, and the Commission directs ATCO Electric, in the compliance filing, to reduce the 2012 closing/2013 opening CWIP balance in the HRTD program by $8.0 million, reduce the 2013 expenditures by $2.0 million, and reduce the 2013 capital additions by $10.0 million. ..... Paragraph 583

48. ATCO Electric planned to reduce the forecast capital expenditures and additions for Project 56539 by $50.0 million in 2013, and increase the capital expenditures and additions for this project by $50.0 million in 2014. It also planned to reduce the forecast capital expenditures and additions for Project 57151 by $10.0 million in 2013, and increase the capital expenditures and additions for this project by $10.0 million in 2014. The Commission directs ATCO Electric to reflect these adjustments in the compliance filing. ..... Paragraph 617

49. However, the Commission agrees with the RPG that there is no justification at this stage for the proposed line length of 58 km in the forecast, when the facility approval is based on a preferred route of 53.7 km. Using information provided by ATCO Electric in an undertaking response, in which it stated that "Included in the PPS estimate of $141 million is the 58 km line cost of $58 million, …" the Commission directs that, in the compliance filing, ATCO Electric reduce the 2013 capital expenditures and 2013 capital additions for this project by $4.3 million, representing the cost associated with the extra 4.3 km of line. ..... Paragraph 631

50. The Commission finds that the forecast for 2014 should be reduced by 50 per cent, to recognize that some of the forecast expenditures are likely to be shifted into years beyond 2014. The Commission directs ATCO Electric, in the compliance filing, to reduce the 2014 forecast expenditures of $55.1 million by 50 per cent. ..... Paragraph 638

51. ATCO Electric provided no documentation to describe this project or explain why it is necessary. In the absence of any information, the Commission finds that it would not be reasonable to include the forecast costs for this project in the test period. The Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures for this project by $3.0 million in 2013, and by $34.7 million in 2014, and to reduce the capital additions for this project by $37.7 million in 2014. ..... Paragraph 644

52. The Commission agrees with ATCO Electric that the 2013 forecast capital expenditures of $3.2 million should be removed, because the project has been cancelled. Accordingly, the Commission directs ATCO Electric, in the compliance filing, to reduce the forecast capital expenditures for 2013 for this project by $3.2 million. The Commission also directs ATCO Electric, in the compliance filing, to reduce the capital additions for this project in 2013 by $3.8 million, to reduce the 2012 closing/2013 opening CWIP balance to zero, and to add the actual expenditures on this project to date into the O&M forecast costs for 2013. The Commission further directs that ATCO Electric provide, in the compliance filing, justification for the prudence of the actual capital expenditures incurred on this project to date. ..... Paragraph 657

53. ATCO Electric planned to remove the forecast capital expenditures of $0.9 million in 2013 and $0.2 million in 2014, along with the forecast capital addition of $1.1 million in 2014, for Project 55624. It also planned to increase the forecast capital expenditures in 2013 for Project 55748 by $1.0 million, and reduce the capital expenditures in 2014 by the same amount. The Commission directs ATCO Electric to reflect these adjustments in the compliance filing. The interveners raised issues with two projects, 55125 and 55185. ..... Paragraph 660

54. The Commission directs ATCO Electric, in the compliance filing, to update its capital forecast by not including any opening work in progress, capital expenditures or capital additions in 2013 and 2014 for Project 55185. ..... Paragraph 671

55. The Commission considers the percentages the RPG provided to allocate its $35.0 million recommended reduction are reasonable. These percentages are 64.3 per cent for 2012 ($22.5 million/$35.0 million), 31.1 per cent for 2013 ($10.9 million/$35.0 million) and 4.6 per cent for 2014 ($1.6 million/$35.0 million). The Commission directs ATCO Electric, in the compliance filing, for the HRTD program, to reduce the 2012 closing/2013 opening CWIP balance by $12.9 million, to reduce the 2013 forecast capital expenditures by $6.2 million, and to reduce the 2014 forecast capital expenditures by $0.9 million. In addition, the Commission directs ATCO Electric, in the compliance filing, to reduce the 2013 forecast capital additions for the HRTD program by $19.1 million, and to reduce the 2014 forecast capital additions for the HRTD program by $0.9 million. ..... Paragraph 702

56. The Commission approves the inclusion of a five per cent contingency for the direct assigned capital projects for the test years as a reasonable forecast. The Commission directs ATCO Electric, in the compliance filing, to include only a five per cent contingency amount in the forecast capital expenditures, capital additions, and year-end CWIP balances for the direct assigned capital projects for 2013 and 2014. The Commission further directs that the compliance filing include details showing the contingency dollar amounts included for each direct assigned capital project's forecast expenditures, additions and closing CWIP balances in each of 2013 and 2014, and how this results in five percent being included for contingencies. ..... Paragraph 752

57. The Commission directs ATCO Electric, in the compliance filing, to reduce its direct assigned capital projects forecast capital expenditures and capital additions in 2013 and 2014 by nine per cent. This reduction should be made after applying any other reductions to the forecast capital expenditures for the direct assigned capital projects for 2013 and 2014 which have been directed by the Commission elsewhere in this decision, including the Commission's directions regarding the contingency amounts in the direct assigned capital projects forecast. The reduction should not include the milestone payments for the EATL project as discussed in paragraph 515 of this decision. Even if no other reductions have been made for a particular direct assigned capital project or group of direct assigned capital projects, the Commission directs that the nine per cent reduction be made. ..... Paragraph 777

58. The Commission considers that a better candidate for an audit would be the entirety of the HRTD program, because this program has a forecast capital cost in excess of $740.0 million. The Commission directs that an audit, under the direction of the Commission, be carried out with respect to the HRTD program, once the program is fully complete. The Commission will provide specific details regarding the audit scope, audit plan, selection

of the independent auditor, and materiality limit in due course. Considering that this audit will be for the entirety of the HRTD program, capital additions for the HRTD program in each year of 2011, 2012, 2013 and 2014 will be approved as placeholders, until the audit is complete. ..... Paragraph 819

59. The forecast for total ES&G costs in the test period may be impacted by other directions included in this decision, as will the resulting ES&G rate. The Commission directs ATCO Electric, in the compliance filing, to update the total ES&G forecast costs and rates for 2013 and 2014, as necessary, to reflect all of the applicable directions included in this decision. ..... Paragraph 831

60. The forecast for total AFUDC costs in the test period may be impacted by other directions included in this decision, as will the resulting AFUDC rate. The Commission directs ATCO Electric, in the compliance filing, to update the total AFUDC forecast amounts and rates for 2013 and 2014, to reflect all of the applicable directions included in this decision. ..... Paragraph 834

61. The Commission directs ATCO Electric, in the compliance filing, to include in its forecast for contributions, the amounts that were included in Schedule 10-8 of the supplementary revenue requirement schedules filed in conjunction with the omissions and updates filing, adjusted for any other directions in this decision that may impact these amounts, and the contributions for any projects where, based on the nature of the project, a contribution will be required. The Commission further directs ATCO Electric to provide, in the compliance filing, a detailed listing of each project for which, based on the nature of the project, a contribution will be required, how the required contribution amount was calculated, whether the contribution has been received by ATCO Electric, and when any contribution that has been received was paid to ATCO Electric by the customer(s). ..... Paragraph 843

62. Last, the contributions forecast includes an amount of $8.6 million in 2014 for Project 50200, transmission arc proofing. Considering that there are no forecast expenditures or additions for this project in either of 2012, 2013 or 2014, the Commission directs ATCO Electric, as part of the compliance filing, to explain why a contribution for this project is forecast in 2014. ..... Paragraph 845

63. In the response to a Commission question on the undertaking responses provided by ATCO Electric, ATCO Electric identified an error with respect to the income tax amounts included in the necessary working capital schedule. In the supporting revenue requirement schedules filed in conjunction with the omissions and updates filing, for each of the years 2011 to 2014, the income tax amounts included in Schedule 11-2 include the federal FIT. When questioned about this, ATCO Electric clarified that the income tax amount in Schedule 11-2 should only include the current income taxes and the "other items," and added that it would incorporate this update in the compliance filing. The Commission therefore directs ATCO Electric, in the compliance filing, to remove any FIT amounts for the years 2011, 2012, 2013 and 2014, when calculating the income tax amounts to be included on the necessary working capital schedule for these years. ..... Paragraph 869

64. The Commission is also aware of a typing error in Schedule 11-3 included as part of the supporting revenue requirement schedules filed in conjunction with the omissions and updates filing. The test period years identified on that schedule are "2011" and "2012." In response to information request AUC-AE-026, ATCO Electric confirmed that these

should read "2013" and "2014." For the sake of accuracy and completeness, the Commission directs ATCO Electric, in the compliance filing, to update Schedule 11-3 that will be submitted as part of the supporting revenue requirement schedules, to include the correct test year labels. ..... Paragraph 870

65. ATCO Electric has not explained why a small portion of the costs included in Schedule 22-1 of the application (isolated generation operating costs) is allocated to the distribution function, or the basis of the allocation. The Commission directs ATCO Electric, in the compliance filing, to explain why some costs included in Schedule 22-1 of the application are allocated to the distribution function, and to explain the basis for the allocation. ..... Paragraph 883

66. One of the cost allocation methodologies uses the average of the percentages for revenue, net PP&E, and capital expenditures (revenue, PP&E and capital expenditures methodology). It is included in schedules 27-1, 27-2, 27-3 and 27-4 of the application. ATCO Electric added that it used 2011 actuals as the inputs in the calculation of this revenue, PP&E and capital expenditures methodology, for the purposes of allocating costs for 2013 and 2014. In Decision 2013-111, the Commission directed that the revenue, PP&E and capital expenditures methodology be revised in order to allocate the ATCO Ltd. group of costs to the ATCO Utilities. The Commission considers that, for consistency and for the same reasons it directed the changes to the revenue, PP&E and capital expenditures methodology in Decision 2013-111, the same changes should be made to the revenue, PP&E and capital expenditures methodology in this decision. The Commission directs that the use of the 2011 actuals as inputs in the calculation of the revised methodology is applicable, because these represent information from two years prior to the first test period. The Commission commented on this in paragraph 134 of Decision 2013-111. ..... Paragraph 884

67. With regard to any amounts included in the application for 2013 and 2014 that were allocated using the revenue, PP&E and capital expenditures methodology, the Commission consequently directs ATCO Electric, in the compliance filing, to update these amounts to reflect the following changes it is directing to the revenue, PP&E and capital expenditures methodology:

    - Capital expenditures must be removed from the allocation methodology.
    - Labour expense must be incorporated into the allocation methodology.
    - Gross revenue must be removed from the allocation methodology and replaced with revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation. ..... Paragraph 885

68. The Commission further directs that the resulting revenue figures be given an equal weighting in the formula, along with labour expense and total assets. ..... Paragraph 886

69. ATCO Electric operates under a deemed common equity ratio and has a relatively small amount of preferred shares. Debt is the residual of the capital structure. As a result, in order to maintain the actual ratios near the deemed levels, the amount of new debt issued is largely determined by the approved growth in rate base. The Commission directs ATCO Electric, in the compliance filing, to update the "Schedule of Debt Capital Employed and Embedded Cost" to include the actual debt issues for 2012. The Commission also directs ATCO Electric, in the compliance filing, to recalculate the amounts of new debt issues for 2013 and 2014 based on the approved growth in rate base

for 2013 and 2014, and to reflect these amounts on the "Schedule of Debt Capital Employed and Embedded Cost." The Commission further directs that the forecast debt issues for 2013 and 2014 included in the compliance filing assume 30-year maturity dates. ..... Paragraph 911

70. The Commission considers that part of the prudent management of the debt costs includes exploring and obtaining any sort of assistance that results in a reduction to debenture rates. Even a small reduction in debt rates, when applied to a large debt amount over a long period of time, can result in significant savings in interest costs. The federal government has provided loan guarantees for certain transmission projects in eastern Canada, and the Commission finds that ATCO Electric should investigate the possibility of obtaining federal and provincial government loan guarantees and assessing the impact on debt costs. The Commission directs ATCO Electric, in its next GTA, to provide details about its efforts to obtain federal and provincial government loan guarantees, and the assessment of any such guarantees. ..... Paragraph 912

71. ATCO Electric operates under a deemed common equity ratio. As a result, in order to maintain the actual equity ratios near the deemed level, the amount of new equity issued (net of any dividends) is largely determined by the approved growth in rate base. The Commission directs ATCO Electric, in the compliance filing, to update the Continuity Schedule of Equity to include the actual equity issues for 2012, to recalculate the amounts of equity issues for 2013 and 2014 based on the approved growth in rate base for 2013 and 2014, and to reflect these amounts on the "Continuity Schedule of Equity." ..... Paragraph 914

72. The Commission directs ATCO Electric to establish a deferral account for debenture rates for the years 2013 and 2014. ..... Paragraph 925

73. The Commission also directs ATCO Electric, in the compliance filing, to add the debenture rate deferral as well as the placeholders for the debenture rates for 2013 and 2014 to the updated Section 1, Attachment 3 schedule that will be submitted. ..... Paragraph 927

74. The government of Canada benchmark bond yield – 10-year yield on September 11, 2013, was 2.78 per cent, and the government of Canada benchmark bond yield – long-term was 3.26 per cent. The omissions and updates filing spread of 148.5 basis points over government of Canada bonds indicates that CU Inc. could issue long-term bonds at 4.745 per cent as at that date. This rate is above ATCO Electric's omissions and updates filing figure of 4.30 per cent, but below ATCO Electric's original 5.10 per cent forecast. The establishment of the deferral account will therefore protect ATCO Electric from the latest increase in rates, but could benefit ratepayers if rates return in 2014 to their 2012 issuance level. The Commission directs ATCO Electric, in the compliance filing, to use 4.745 per cent as the 2013 and 2014 placeholder for long-term debt. ..... Paragraph 938

75. No evidence has been produced with respect to the historical forecasting accuracy of ATCO Electric with respect to dividend reset rates. There is evidence on the record with respect to the forecasting accuracy of new preferred share issues. This information shows that the actual preferred share rate in 2009 was greater than the forecast, while the actual preferred share rate in 2010 was less than the forecast. The Commission considers that this is no evidence of a pattern of over forecasting, and finds that there is no reason to accept the CCA's recommended rate over the rate proposed by ATCO Electric. The

Commission approves the forecast preferred share rate reset of 4.80 per cent for 2014 and directs ATCO Electric to use this rate in the compliance filing. ..... Paragraph 946

76. Attachment 1, Schedule 2(a) to the response to information request CCA-AE-45(a) shows that the credit facility costs were allocated to the various CU Inc. and Canadian Utilities Limited subsidiaries using the cost allocation methodology that is based on the average of revenues, assets, and capital expenditures. In Decision 2013-111, the Commission directed that there should be changes to the allocation methodology used to allocate the ATCO Ltd. corporate costs. The Commission considers that, for consistency and for the same reasons it directed the changes to the allocation methodology in Decision 2013-111, the same changes should be made to the revenues, assets and capital expenditures methodology used to allocate the cost of the credit facilities. The Commission directs that the 2011 actuals should be used as inputs in the calculation of the revised methodology, as these represent information from two years prior to the first test period. The Commission commented on this in paragraph 134 of Decision 2013-111. .. Paragraph 954

77. Therefore, with regard to calculating the allocated share of the credit facility costs for 2013 and 2014, the Commission directs ATCO Electric, in the compliance filing, to update these amounts to reflect the following changes it is directing to the revenue, assets and capital expenditures methodology:

- Capital expenditures are to be removed from the allocation methodology.
- Labour expense is to be incorporated into the allocation methodology.
- Gross revenue is to be removed from the allocation methodology and replaced with revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation. ..... Paragraph 955

78. The Commission further directs that the resulting revenue figures be given an equal weighting in the formula along with labour expense and total assets. ..... Paragraph 956

79. ATCO Electric's position on the need to collect provincial FIT relied on the need to meet the credit metrics it proposed were required. The Commission agrees with the UCA's analysis that the collection of provincial FIT is not required to meet the credit metrics determined as set out in Decision 2009-216, and therefore denies ATCO Electric's request to recover provincial FIT. The Commission directs ATCO Electric, in the compliance filing, to remove provincial FIT from the income tax component of the revenue requirements for 2013 and 2014, and to update the remaining revenue requirement schedules as applicable, to reflect the removal of provincial FIT. ..... Paragraph 984

80. In Section 14.7 of this decision the Commission has rejected ATCO Electric's request to recover provincial FIT as part of the revenue requirements for 2013 and 2014. The Commission directs ATCO Electric, in the compliance filing, to update the applicable no cost capital schedules to reflect this finding. ..... Paragraph 1002

81. The Commission directs ATCO Electric, as part of the compliance filing, to update any schedules in Section 30 of the application, to reflect any updated amounts included in the supplementary revenue requirement schedules that will be submitted as part of the compliance filing, so that the schedules are consistent. The Commission further directs ATCO Electric to prepare schedules 30-12, 30-13 and 30-14 in the same format used in the application, which included the corporate totals for isolated generation, general O&M, common operations, and corporate A&G. The Commission has also previously

directed ATCO Electric, in Section 5.2.1 of this decision, to submit supplementary schedules that show only the transmission function's share of the ATCO I-Tek volumes for 2013 and 2014. ..... Paragraph 1009

82. The Commission agrees that the direct assigned capital projects deferral account balance should be updated to account for this disposition, and considers that any property taxes related to this land that were paid in 2011 should be removed from the calculation of the "taxes other than income" deferral account balance for 2011. The Commission directs ATCO Electric, in the compliance filing, to update the calculation of the direct assigned capital projects deferral account balance for 2011 to reflect the disposition of the land described in Decision 2013-221, to advise whether any property taxes were paid on this land during 2011, and to exclude such property taxes from the calculation of the 2011 "taxes other than income" deferral account balance. ..... Paragraph 1013

83. ATCO Electric included carrying costs to the end of May 2013. This needs to be updated to reflect the fact that the deferral account balances were not approved at the end of May 2013, and will not be approved as part of this decision because of updates that are required in the compliance filing. Therefore, the Commission directs ATCO Electric, in the compliance filing, to update the carrying costs calculations to reflect ATCO Electric's expected date for the one time refund of the deferral account balances to the AESO. ..... Paragraph 1023

84. During its review of the carrying costs calculation in Schedule 12.0 of Section 32 of the application, the Commission observed that, included in the calculation of the $0.679 million carrying costs associated with the 2011 interim to final true up amount, are carrying costs for the months of January 2012 to May 2013 inclusive, even though there is no principal balance associated with the "AESO interest" category for these months. Because the principal balance was no longer in place for these months, ATCO Electric is not entitled to carrying costs for these months. The Commission directs ATCO Electric, in the compliance filing, to not include any carrying costs associated with the "AESO Interest" category for any month after December 2011. ..... Paragraph 1024

85. This should not diminish the effectiveness of ATCO Electric's efforts to attract and retain employees, because these potential employees will still be eligible for VPP. The Commission is not eliminating the entire VPP for these positions, but rather is requiring ATCO Electric to revise the structure of the VPP for these positions. This adjustment only applies to a small number of senior individuals. The Commission directs ATCO Electric, in the compliance filing, to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent. ..... Paragraph 1042

86. ATCO Electric is responsible for demonstrating the reasonableness of its forecast amounts. ATCO Electric has not provided any of the assumptions upon which it relied in calculating its VPP forecasts. In the circumstances, it is not unreasonable for the Commission to assume that not all of the employees eligible for VPP will meet 100 per cent of the targets set for them, and that not all FTEs eligible for VPP will be with ATCO Electric when the VPP payouts are made. Consequently, a reduction to the VPP forecast amounts is required because ATCO Electric has not demonstrated that a 100 per cent payout is justified, and the Commission considers that only 90 per cent of the forecast payout can reasonably be included in revenue requirement, after the revision directed in paragraph 1042 of this decision is made. The Commission directs ATCO Electric, in its

compliance filing, to reduce the resulting entire VPP amounts for 2013 and 2014 by 10 per cent in each year. ..... Paragraph 1049

87. In response to an undertaking given by an ATCO Electric witness, ATCO Electric acknowledged that certain corrections were required in schedules 23-1, 24-1 and 25-11 with respect to VPP amounts for general O&M employees. In that undertaking response ATCO Electric stated that it would reflect these amendments to the three schedules in the compliance filing. The Commission considers that for the sake of completeness these corrections should be made and therefore directs ATCO Electric, as part of the compliance filing, to include the corrections identified in Exhibit 146.01. Paragraph 1050

88. While the Commission acknowledges that the amount of land and the associated cost is not material to the overall revenue requirements being applied for, it is important for ATCO Electric to make sure that all assets that are included in rate base are required for utility purposes. It appears from the testimony provided by the ATCO Electric witness that only five acres of the remaining seven acres will be used, although there is uncertainty about this. The Commission directs ATCO Electric, in the compliance filing, to provide an update with respect to the remaining seven acres of land at the Drumheller service building project site, and remove any land that is not going to be used in the provision of utility service in either 2013 or 2014. The Commission further directs that for any land removed, the resulting revenue requirement reduction include return, property taxes and any other areas that are directly impacted. ..... Paragraph 1068

89. With respect to the current administrative building located in Drumheller and its use once the new two story administrative and technical building is built at the warehouse site, Mr. Babyn stated that it will continue to be used until the new building is in service in 2014, at which time the continued use will be assessed. Considering the uncertainty of the future use of the current administrative building in Drumheller, the Commission directs ATCO Electric, in its next GTA, to include an update on the status of the current administrative building in Drumheller and how, if it is included in rate base in the next GTA, such a facility is being used in the provision of transmission utility service. ..... Paragraph 1069

90. ATCO Electric submitted details of the calculations of the farm transmission costs for 2013 and 2014 in response to information request AUC-AE-016. The revenue requirement amounts for 2013 and 2014 are $3.7 million and $4.1 million respectively. The main reason for the increase in the total farm transmission costs between 2012 and 2013, and 2013 and 2014, is due to the return and depreciation associated with the forecast increase in mid-year rate base. The mechanical calculations have been made correctly. On this basis, the Commission considers the forecast to be reasonable, and approves the forecast farm transmission costs of $3.7 million for 2013 and $4.1 million for 2014. The Commission directs ATCO Electric to reflect these approved farm transmission costs for 2013 and 2014, as detailed in the response to information request AUC-AE-016, in the compliance filing. ..... Paragraph 1076

91. For the sake of completeness and transparency, all separately identifiable capital projects, even when they are part of an overall larger project, should be shown on the schedule of capital expenditures; this will enable parties to examine the complete nature of the overall larger project on a more detailed level. The Commission directs ATCO Electric, in all future GTAs, to provide details of each capital project on an individual basis, on the schedule of capital expenditures. ..... Paragraph 1093

92. The Commission directs ATCO Electric, in its next transmission GTA and next annual transmission deferral account application, to include the following additional information with respect to any individual direct assigned capital project that has a forecast capital cost in excess of $5.0 million:

- project milestone schedules and the timing of capital expenditures
- AESO change order requests and authorizations
- cost estimates at the stages described in paragraph 1082 of this decision
- cost estimates by the categories described in paragraph 1084 of this decision
- the preliminary engineering costs included in the cost estimates
- the detailed engineering costs included in the cost estimates
- schedules of project attributes, for both transmission line projects and substation projects, similar to the information provided in response to information request IPCAA-AE-008(c)
- parametric values that are derived through the use of parametric estimating techniques
- the current AESO functional specifications
- bulk transmission line optimization studies where required by ISO Rule 502.2
- post completion reports
- 60-day and 150-day reports that are filed in response to the AESO's rules

..... Paragraph 1096

Appendix 4 – Acronyms and abbreviations

Acronym/abbreviation	Name in full
A&G	administrative and general
AC	alternating current
ADC	Alberta Direct Connect Consumers Association
AESO	Alberta Electric System Operator
AFUDC	allowance for funds used during construction
ATCO Electric	ATCO Electric Ltd.
AUC	Alberta Utilities Commission
Bechtel	Bechtel Canada Co.
CSA	Canadian Standards Association
CCA	Consumers' Coalition of Alberta
CCES	Construction Cost Escalator Study
CEA	Canadian Electricity Association
CETD	Central East Transmission Development
CEWA	Canadian Energy Workers Association
CIAC	contributions in aid of construction
Commission	Alberta Utilities Commission
CPI	Consumer Price Index
CWIP	construction work in progress
DC	direct current
EARA	Early Access and Resolution Agreement
EATL	Eastern Alberta Transmission Line
EBIT	earnings before income tax
EPCM	engineering, procurement and construction management
ERCB	Energy Resources Conservation Board
ES&G	engineering, supervision and general
EUB	Alberta Energy and Utilities Board
FFO	funds from operations
FIT	future income taxes
FTE	full-time equivalent
GTA	general tariff application
HRTD	Hanna Regional Transmission Development
HVDC	high voltage direct current
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards

Acronym/abbreviation	Name in full
IPCAA	Industrial Power Consumers Association of Alberta
IR	information request
ISD	in-service date
ISO	Independent System Operator
km	kilometre
kV	kilovolt
kVA	kilovolt-ampere
kW	kilowatt
LCVM	Life Cycle Value Management
Mercer	Mercer (Canada) Limited
MFR	minimum filing requirements
MVA	megavolt-ampere
NCTD	North Central Transmission Development
NERC	North American Electric Reliability Corporation
NETD	North East Transmission Development
NFMTD	North Fort McMurray Transmission Development
NID	needs identification document
O&M	operation and maintenance
PBR	performance-based regulation
PP&E	property, plant and equipment
PPS	proposal to provide service
PUB	Public Utilities Board
RFP	request for proposal
RPG	Ratepayer Group
SAGD	steam assisted gravity drainage
SCADA/EMS	Supervisory Control and Data Acquisition/Energy Management System
SIP	statement of intent to participate
TCRS	Transmission Cost Recovery Subcommittee
TFCMC	Transmission Facilities Cost Monitoring Committee
TFO	transmission facility owner
TGS	TransGrid Solutions Ltd.
UCA	Office of the Utilities Consumer Advocate
VPP	variable pay program
WATL	Western Alberta Transmission Line

I

Decision **20272-D01-2016**

ATCO Electric Ltd.

2015-2017 Transmission General Tariff Application

August 22, 2016

Alberta Utilities Commission
Decision 20272-D01-2016
ATCO Electric Ltd.
2015-2017 Transmission General Tariff Application
Proceeding 20272

August 22, 2016

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Alberta Utilities Commission
Calgary, Alberta

ATCO Electric Ltd. **Decision 20272-D01-2016**
2015-2017 Transmission General Tariff Application **Proceeding 20272**

Decision

1. This decision reflects the Alberta Utilities Commission's (the AUC or the Commission) determination of ATCO Electric Ltd.'s (ATCO Electric) 2015-2017 Transmission General Tariff Application (GTA). The Commission found that not all of the amounts forecast for inclusion in revenue requirement during the test period were reasonable and, consequently, revised them downward. The Commission also declined to approve certain changes to depreciation methodology proposed by the utility and approved the continuation of some, but not all, previously available credit metric supports.

2. The Commission found that ATCO Electric had demonstrated compliance with a number of the directions contained in its prior GTA decision (Decision 2013-358[1]), and other related decisions, as identified in Appendix 4 of this decision. The Commission approved ATCO Electric's continued use of its terms and conditions of service, as filed.

3. The Commission directed certain adjustments to forecasting methodologies and key assumptions proposed by ATCO Electric. The directed adjustments primarily related to assumptions regarding staffing requirements and various escalation factors.

4. The request for deferral account treatment for fuel costs was not approved. The Commission directed the use of reserve account treatment for variable pay program costs and vegetation management expenditures.

5. The Commission downwardly revised ATCO Electric's proposed operating cost forecasts for manpower, severance costs and vegetation management. The Commission did not approve the implementation of a revised cost allocation for telecommunications services subject to a shared services arrangement between ATCO Electric Ltd.'s transmission and distribution divisions.

6. The Commission found that the use of forecasts relying on a zero-based approach employed by ATCO Electric is acceptable.

7. Various changes to depreciation methodology requested by ATCO Electric, including the use of forecast retirements and costs of retirement in determining depreciation parameters, were not approved. The Commission also confirmed the continued use of current depreciation process, methodologies and practices including gradualism and moderation in regulatory depreciation practice and provided various directions regarding the depreciation parameters of service life, Iowa curve and net salvage percentages.

[1] Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Proceeding 1989, Application 1608610-1, September 24, 2013.

8. The Commission did not approve recovery of forecast costs for several capital projects identified in ATCO Electric's application. Several project forecasts were not approved owing to uncertainty regarding the likelihood of their construction or completion during the test period. Recovery of amounts associated with other capital projects were denied on the basis that no, or no minimum filing requirement (MFR)-compliant, business case had been provided.

9. ATCO Electric's request for placeholder amounts of $10 million for each of the last two test years to defray the costs of the utility obtaining third-party line insurance was denied. The Commission found that permitting the utility to recover such costs in rates would be inconsistent with utility asset disposition (UAD) principles. The Commission approved ATCO Electric's continued use of a reserve for injuries and damages (RID) account.

10. The Commission approved the continuation of federal future income tax (FIT) amounts in ATCO Electric's revenue requirement for the test period. ATCO Electric's request for the continued inclusion of construction work in progress (CWIP) and recovery of the capital portion of pension costs on a cash basis as credit supports were approved for each of 2015 and 2016, but denied for 2017.

11. The Commission approved ATCO Electric's proposed accounting treatment in respect of its participation in the West Fort McMurray Transmission project (WFMAC), subject to additional reporting requirements intended to ensure that neither service quality nor rates were adversely affected.

12. The Commission ordered ATCO Electric to refile its 2015-2017 Transmission General Tariff Application by September 30, 2016, to reflect the findings, conclusions, and directions in this decision.

13. At the time of the refiling, it is expected that the full impact of this decision will be known and final rates for the test period can be set following the Commission's assessment of whether the refiling is compliant with determinations in this decision.

1 Introduction

14. On March 16, 2015, ATCO Electric filed a revenue requirement application with the Commission for each of the years 2015, 2016 and 2017.

15. Subsequent to submission of the initial application, ATCO Electric filed numerous updates, starting in May 2015 and continuing into March 2016. Information on the more substantive updates are listed below:

- May 12, 2015 update for depreciation changes, 2014 actuals, and 2013 generic cost of capital (GCOC) impacts. Exhibit 20272-X0219.

- October 2, 2015 omissions and updates (O&U) filing including updates for capital, credit relief, full time equivalent employees (FTEs), severance costs, insurance costs, property taxes, inflation, operating and maintenance (O&M), and numerous other items. Exhibit 20272-X0604.

- October 30, 2015 update for 2015 actual debt financing. Exhibit 20272-X0620.

- December 16, 2016 update for impacts of ATCO workforce reductions, common group placeholders, vegetation management and to rescind its request that the Commission grant certain exemptions to compliance with the Affiliate Code of Conduct. Exhibit 20272-X0700.

- January 13, 2016 updates for capital costs, severance costs, FTE additions and vacancy rates, and information technology (IT) impacts resulting from the ATCO workforce reductions. Exhibit 20272-X0736.

- February 23, 2016 revised version of the complete application to reflect the most current information. Exhibit 20272-X1098.

- March 3, 2016 updates for common group placeholders and capital. Exhibit 20272-X1135.

16. As part of its updated application, ATCO Electric sought the following:

- That the Commission agree to consider and approve its application for revenue requirements for each of the three test years, 2015, 2016 and 2017 (also referred to as the general tariff application or GTA with a three-year test period).
- That ATCO Electric rates to be paid by the Alberta Electric System Operator (AESO) for the use of ATCO Electric's facilities over the test period be based on ATCO Electric's forecast revenue requirements.
- That existing deferral account treatment be extended through the test period for the following costs:
    - defined benefit special payments
    - right-of-way payments
    - property taxes
    - income taxes relating to:
        - (i) rates
        - (ii) capital repair costs
        - (iii) deductions of deferrals for tax purposes
    - direct assigned capital
    - long-term debenture rates
    - effects of International Financial Reporting Standards (IFRS) adoption

- That new deferral accounts be approved for use during the test period for the following:
    - fuel costs
    - costs related to amendments to the *Electric Utilities Act* or the regulations thereunder, or arising from AUC-approved tariffs for the test period for ATCO Electric or other industry participants.

- That the AUC approve the use of updated depreciation parameters supported by the depreciation study prepared for ATCO Electric by Gannett Fleming.

- That the AUC approve continued recovery of construction work in progress (CWIP), in rate base for direct assigned transmission projects, continued use of federal future income

taxes (FIT) for inclusion in revenue requirement, and recovery of the capitalized portion of pension costs.

- That recovery of head office costs using each year's second prior year actual amounts to derive the allocation factors be approved.

- That operating costs related to corporate license fees that ATCO Electric is required to pay to ATCO Ltd., be approved for inclusion in revenue requirement.

- That placeholder treatment be approved for the following:
  - return on equity and common equity ratio
  - defined benefit plan pension costs
  - line insurance costs
  - common group costs
  - corporate license fees
  - IT common matters costs (based upon GTA IT volumes)

17. In its updated application, ATCO Electric requested approval of the following revenue requirement amounts for 2015, 2016 and 2017. The revenue requirement requests amount to increases of 24.5 per cent in 2015, 17.3 per cent in 2016 and an additional 4.6 pe rcent in 2017.

Table 1. Comparison of revenue requirement for 2014-2017

Description	2014 actual	Test period		
		2015	2016	2017
	($ million)			
Revenues				
Transmission tariffs	561.4	721.1	845.6	884.4
Deferral accounts	2.2	-	-	-
Total revenues	563.6	721.1	845.6	884.4
Costs				
Fuel	8.3	6.4	8.2	8.8
Operating costs	114.8	186.8	197.9	220.5
Depreciation	130.9	218.4	300.9	311.0
Return on rate base	293.8	309.2	312.1	312.3
Income tax expense	22.6	31.6	45.8	49.9
Revenue offsets	(6.7)	(31.3)	(19.3)	(18.1)
Total costs	563.6	721.1	845.6	884.4
Transmission tariffs		721.1	845.6	884.4
Revenue at existing rates		579.0	579.0	579.0
Increase		142.1	266.6	305.4
% cumulative increase		24.5%	46.0%	52.8%
% annual increase		24.5%	17.3%	4.6%

Source: Based on Exhibit 20272-X1101, Schedule 3-1 Transmission Revenues and Costs.

18. Notice of the original application was provided to parties on the Commission's eFiling System on March 18, 2015 and can be found on the eFiling system, listed as Exhibit 20272-X0135.

19. The Commission received Statements of Intent to Participate (SIPs) from the following parties:

- AltaLink Management Ltd. (AltaLink)
- Alberta Direct Connect Consumers Association (ADC)
- Industrial Power Consumers Association of Alberta (IPCAA)
- Consumers' Coalition of Alberta (CCA)
- Office of the Utilities Consumer Advocate (UCA)
- The City of Calgary (Calgary)

20. IPCAA, the CCA, the UCA, ADC and Calgary actively participated in the proceeding. The CCA, ADC and IPCAA also worked together as members of a coalition identified as the Ratepayer Group (RPG).

21. Parties who registered as interveners for this proceeding are listed in Appendix 1 to this decision. Parties who participated in the oral hearing are listed in Appendix 2 to this decision.

22. A summary of main process steps followed in this proceeding is provided below:

Table 2. Summary of process and schedule for proceeding

Process step	Deadline
Participation closing date	April 1, 2015
Round 1 information requests (IRs) to ATCO Electric - non depreciation	June 8, 2015
Round 1 IR responses from ATCO Electric – non depreciation	July 3, 2015
Round 2 IRs to ATCO Electric - depreciation	July 10, 2015
Round 2 IR responses from ATCO Electric – depreciation	July 31, 2015
Round 3 IRs to ATCO Electric	October 16, 2015
Round 3 IR responses from ATCO Electric	November 4, 2015
Round 4 IRs to ATCO Electric	December 30, 2015
Round 4 IR responses from ATCO Electric	January 13, 2016
Intervener evidence	January 20, 2016
IRs on intervener evidence	February 1, 2016
IR responses from interveners on intervener evidence	February 11, 2016
Rebuttal evidence from ATCO Electric	February 23, 2016
Oral Hearing - commencement	March 9, 2016
Oral Hearing – conclusion (14 business days)	March 30, 2016
Argument	May 9, 2016
Reply argument	May 24, 2016

23. A summary of the rulings and procedural requests that, for the most part, preceded the hearing is provided in Appendix 3.

24. The Commission considers, for the purposes of this decision, that the record for Proceeding 20272 closed on May 24, 2016.

25. The Commission is a public body and, as such, unless otherwise directed, all documents submitted to the Commission, as well as all decisions of the Commission, are publicly available.

The Commission granted confidential treatment to a discrete portion of the evidence on the record of this proceeding and held a portion of the proceeding *in camera*.

26. In reaching the determinations set out in this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence, argument and reply argument provided by each party and including the evidence and testimony heard *in camera*. 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. The Commission has determined that no separate confidential decision is required in this case.

2 Background to the application

27. Over the past several years in Alberta, there has been a high level of transmission capital expenditure. Most of these projects are now either completed and in rate base, or in the final stages of construction. These projects included the $1.8 billion Eastern Alberta Transmission Line (EATL) which was energized in December 2015. ATCO Electric's previous GTA had forecast total capital expenditures of $1.5 billion and $1.2 billion for 2013 and 2014, respectively.

28. In its updated application, ATCO Electric is forecasting a significant reduction to the level of total capital expenditures from $1.2 billion in 2014 to $0.4 billion for each of 2015, 2016 and 2017. Total direct assigned capital expenditures for 2014 were $1.1 billion, falling to forecasts of $0.2 billion in each of 2015 and 2016, and $0.3 billion for 2017. The utility attributed these decreases in large part to its analysis of the updated AESO Long-Term Transmission Plan.

29. In ATCO Electric's initial application, total forecast capital expenditures were $0.5 billion for each of 2015 and 2016, followed by $1.0 billion for 2017. Total direct assigned capital expenditures were $0.4 billion for each of 2015 and 2016, followed by $0.8 billion for 2017.

30. ATCO Electric explained that its capital expenditures forecast is based on various factors, including the AESO's Long-Term Transmission Plan and discussions with both the AESO and customers.[2] ATCO Electric revised its direct assigned capital forecast in response to the updated AESO Long-Term Transmission Plan received towards the end of 2015.

31. In response to a Commission IR[3] on the impact of lower oil prices on ATCO Electric's forecast revenue requirement, the utility stated that its information regarding this factor came from discussions with the AESO and customers about their expected levels of economic activity:

> To forecast capital expenditures, AET contacted the AESO and AET customers directly to obtain information on plans to move forward with their projects requiring transmission infrastructure. Based on this information, AET developed both cost and timing forecasts. AET was aware of the forecasted economic downturn at the time the GTA forecasts were developed and reflected the impacts of the downturn by incorporating the available

[2] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 134.
[3] Exhibit 20272-X0284, response to IR AET-AUC-2015JUN08-002 parts c and f, PDF pages 4-8.

> information obtained directly from those making decisions about the level of economic activity to undertake.
>
> …
>
> …. declining oil prices affect economic activity in Alberta, which impacts AET in the areas of capital expenditures, inflation rates including labour cost forecasts, and long term debt rates. AET's forecast revenue requirement is impacted indirectly as it is impacted by the factors discussed above.
>
> Capital maintenance activities are driven by the condition, age, performance, and risk related to the transmission assets and are not impacted by economic activity.

32. In its current application, ATCO Electric highlighted the main cost drivers for the significant annual revenue requirement increases requested of 24.5 per cent, 17.3 per cent and 4.6 per cent for 2015 2016 and 2017, respectively, as follows:

> The main driver for the Transmission revenue requirement increase is the capital related costs (return, income tax and depreciation) associated with increases in Transmission rate base, including the revenue requirement impact of including Transmission Directed Assigned CWIP in rate base. Other drivers include the impact of recovering higher operating costs.[4]

33. Decision 20338-D01-2015[5] issued on June 24, 2015 approved a 2015 interim tariff of $626.1 million included in this application, which was based on 90 per cent of the May 12, 2015 updated 2015 revenue requirement.[6] Decision 21051-D01-2016[7] issued on January 29, 2016 approved a 2016 interim tariff of $758.9 million included in this application, which was based on 90 per cent of the December 16, 2015 updated 2016 revenue requirement.[8]

34. ATCO Electric has proposed the continued use of existing deferral accounts along with the addition of some new accounts. One of the larger existing deferral accounts is that for direct assigned capital. Given the high level of transmission capital expenditures in recent years, and the fact that the majority of these capital projects are now completed and in rate base, the amount of direct assigned capital in rate base constitutes a material portion of the revenue requirement. When Mr. Levson, representing the RPG, was questioned by Chairman Grieve during the hearing, he estimated that the percentage of revenue requirement attributable to direct assigned projects was in the range of 80 to 90 per cent.[9]

35. The revenue requirement for the current proceeding also includes placeholders for amounts that will be determined in other proceedings. These include:

- Proceeding 21701 Common Group placeholders for 2016 and 2017
- Proceeding 21029 Corporate License Fees placeholders for 2015, 2016 and 2017

[4] Exhibit 20272-X1100, application, paragraph 13, PDF page 11.
[5] Decision 20338-D01-2015: ATCO Electric Ltd., 2015 Updated Interim Transmission Facility Owner Tariff, Proceeding 20338, June 24, 2015.
[6] Exhibit 20272-X0217, updated GTA schedules, Schedule 3-1.
[7] Decision 21051-D01-2016: ATCO Electric Ltd., 2016 Interim Transmission Facility Owner Tariff, Proceeding 21051, January 29, 2016.
[8] Exhibit 20272-X0700, AET response to December 4, 2015 Commission ruling.
[9] Transcript, Volume 13, page 2459.

- Proceeding 20514 IT Common Matters placeholders for price only, as the current proceeding will establish volumes.

36. In addition, a ruling at the beginning of the current proceeding directed ATCO Electric to file the Hanna Regional Transmission Development (HRTD) audit, which was submitted in the current application, as part of a proceeding the Commission will establish in due course to address the audit, as detailed in Direction 58 of Decision 2013-358.[10] In the ruling, the Commission stated that it would not evaluate the sufficiency of the audit with respect to compliance in the current proceeding, nor consider which party would bear the cost of the audit.

37. In Proceeding 3524 for AltaLink Management Ltd.'s 2015-2016 GTA, AltaLink being the other comparable transmission utility in the province, the Commission considered certain issues common to those raised in the current proceeding including depreciation and credit metrics.

2.1 Preliminary decisions

2.1.1 Test period

38. ATCO Electric proposed using a three-year test period including 2017, stating that this would mitigate regulatory costs, increase regulatory efficiency and maintain rate prospectivity.[11] It submitted that because the application was filed within two years of the start of the third test year and a significant infrastructure build would be completed *prior* to the third test year, the proposed revenue requirement forecast for 2017 was reasonable and conservative.

39. At the start of this proceeding, the CCA filed a motion which raised concerns over ATCO Electric's use of a three-year test period in uncertain economic conditions "…. which could materially alter forecasts of inflation, supplier competitiveness and resource availability during the test period. The further out the forecast, the greater the uncertainty associated with the forecast…."[12]

40. The CCA submitted that if the Commission did not limit the test period to two years, the uncertainty could be addressed by the use of "placeholders for inflation factors, salaries and wages escalation and contractor inflation in conjunction with a mechanism for forecasts for the third test year to be updated for inflation and escalation factors prior to commencement of that year." In its view, "[t]he simplest approach to updating the above mentioned factors would be to reference proxy indicators of inflation and escalation such as forecast consumer price index (CPI) and forecast changes in Alberta average wages and salaries per employee."[13]

41. The RPG expressed the following three concerns[14] with including 2017 as a test year:

- Due to historical over-earning by ATCO Electric over the last 10 years, including 2017 provides little or no future benefit or savings to customers.

[10] Exhibit 20272-X0182, Commission ruling, paragraph 52, PDF page 10.
[11] Exhibit 20272-X1100, application, paragraph 31, PDF page 17.
[12] Exhibit 20272-X0168, CCA motion, paragraph 4, PDF page 2.
[13] Exhibit 20272-X0168, CCA motion, paragraph 7, PDF page 2.
[14] Exhibit 20272-X1297, RPG argument, paragraphs 130-131, PDF page 59.

- As a result of the economic uncertainty in Alberta and the significant increase in forecast revenue requirement, there is a risk that forecast 2017 costs will materially differ from actual 2017 costs.

- ATCO Electric has not demonstrated that the potential benefits of including the third test year outweigh the potential costs of excluding it. Disallowing the third test year would provide ATCO Electric the opportunity to prepare a detailed zero-based budget for 2017 as part of its next GTA.[15]

42. The RPG recommended that the 2017 test year be excluded and that ATCO Electric be directed to refile its 2017 forecast revenue requirement in its next GTA after performing a detailed zero-based budgeting exercise.[16]

43. ATCO Electric argued that it had updated its GTA most recently on February 23, 2016, and provided revised forecasts based on the most current information available to it. The utility claimed that this update had utilized 2015 information that was available just prior to year-end, resulting in "…. an excellent forecast for 2015 and very good forecasts for 2016 and 2017."[17]

44. ATCO Electric further submitted that since a decision on the current GTA is not expected until close to the commencement of 2017, requiring a new proceeding for 2017 would result in duplication and redundancy, not regulatory efficiency.[18]

Commission findings

45. In a ruling issued in response to the CCA motion to exclude the 2017 test year, the Commission determined that the 2017 test year would not be excluded but that the onus remained with ATCO Electric "to support all aspects of the application, including the reasonableness of forecasts for each of the test years, and demonstrating that it is in the public interest to include each test year in its application."[19]

46. The Commission considers that, in certain circumstances, the use of a three-year test period could increase regulatory efficiency and reduce regulatory costs. However, this will not always be the case. Subsequent determinations of test periods will depend on the facts of the particular proceeding. In the current proceeding, the utility's original application was filed approximately eight months later than anticipated and was extensively updated several times. The revenue requirement requested by ATCO Electric for the three test years was also revised several times. Processing the application involved an unusually large number of motions, multiple rounds of information requests and multiple requests from various parties for extensions to filing deadlines.

47. The Commission considers that gains in regulatory efficiency must be weighed against the potential loss of forecast accuracy occasioned by use of a three-year test period. In this case, any increased regulatory efficiency that might otherwise have been captured through the use of an extended test period was largely, if not entirely, eroded by the protracted period of record development resulting from numerous updates and interlocutory steps. These same factors,

[15] Exhibit 20272-X1297, RPG argument, paragraph 130, PDF page 59.
[16] Exhibit 20272-X1297, RPG argument, paragraph 152, PDF page 64.
[17] Exhibit 20272-X1298, AET argument, paragraph 385, PDF pages 148-149.
[18] Exhibit 20272-X1309, AET reply argument, paragraph 257, PDF page 109.
[19] Exhibit 20272-X0182, Commission ruling on CCA motion, paragraph 18, PDF page 4.

however, have served to significantly mitigate the potential loss of forecast accuracy over the three-year test period. The Commission is able to rely on actual results for the first test year and part of the second test year which, at this point, is itself more than half over. In addition, a revised version of the complete application, including updated forecasts, was filed just two weeks prior to the start of the oral hearing. As a result, there is far less reason to be concerned about forecast accuracy and a three-year test period that includes 2017 than would have been the case had the application been submitted prior to the first test year, without subsequent updates. In practical terms, the Commission is dealing with a test period that comprises one full year of actual results, and something less than two complete years that rely on forecast information. This, in itself, is not unreasonable and provides insufficient basis for the Commission to exclude the year 2017 from the proposed test period.

48. The Commission also finds that excluding 2017 as a test year and requiring that it be the first test year of the next ATCO Electric GTA would lead to considerable duplication and redundancy, contrary to the objective of regulatory efficiency.

49. For all of the above reasons, the Commission approves the use of the test years 2015 to 2017.

2.1.2 Use of forecasting on a "zero-based" approach

50. In Decision 2013-358, the Commission stated that forecasts are best developed from "an assumed zero-base, which seeks to reassess resources and costs required to fulfill [ATCO Electric's] statutory duties on an annual basis."[20] However, Decision 2013-358 did not contain a direction requiring ATCO Electric to develop its future GTA forecasts using a "zero-based" approach.

51. In its evidence, FTI submitted, on behalf of the RPG, that ATCO Electric did not adequately support its requested revenue requirement because it did not prepare its forecasts using a zero-based methodology.

52. ATCO Electric explained in the current application that it uses an "activity-based forecasting approach," which it described during the oral hearing as "a ground-up assessment of the activities required and worked through with staff and managers responsible for executing the budgets and arrived at the plan that's included in this general tariff application."[21]

53. As reflected in subsequent parts of this decision, the Commission finds that ATCO Electric's activity-based approach to budgeting accords with the Commission's expressed preference that forecasts be developed from an assumed zero base.

54. In Section 7.1 and Section 11.1.3 of this decision, the Commission examines the use of forecasts relying on a "zero-based" approach for O&M and capital forecasts, respectively.

3 Responses to previous Commission directions

55. In its application, ATCO Electric responded to 15 directions issued in Decision 2013-358 dealing with the ATCO Electric Ltd. 2013-2014 Transmission GTA. ATCO Electric also

[20] Decision 2013-358, paragraph 163.
[21] Transcript, Volume 2, page 312.

responded to one direction from Decision 2013-417[22] regarding Utility Asset Disposition, one direction from Decision 2014-167[23] regarding the ATCO Electric Ltd. 2013-2014 Transmission GTA Compliance Filing, and two directions from Decision 2014-283[24] regarding the ATCO Electric 2012 Transmission Deferral Account and Annual Filing. The CCA and the RPG submitted that there were a number of Commission directions which ATCO Electric had not properly addressed. In this decision, the Commission has provided detailed reasons for its findings regarding directions in respect of which parties or the Commission have identified issues or concerns or for which further direction is required. The Commission has reviewed the record as it pertains to all other directions and is satisfied that ATCO Electric's responses comply with the directions given and that no further action is required.

56. All directions which the Commission has determined ATCO Electric has complied with are set out in Appendix 4 of this decision. The Commission is satisfied that the application adequately addresses and responds to those directions and, accordingly, accepts ATCO Electric's responses to directions 1, 2, 3, 24, 25, 27, 31, 36, 38, 39, 70, 89 and 92 from Decision 2013-358, Direction 2 from Decision 2013-417, Direction 4 from Decision 2014-167, and directions 5 and 6 from Decision 2014-283.

57. The Commission finds that ATCO Electric has not complied with directions 42 and 58 from Decision 2013-358. The Commission addresses Direction 42 in subsequent sections of this decision. ATCO Electric's response to Direction 58 is discussed below.

3.1 Direction 58 – Hanna Regional Transmission Development (HRTD) cost and performance audit

58. In paragraph 819 of Decision 2013-358, the Commission issued the following direction to ATCO Electric:

> The Commission considers that a better candidate for an audit would be the entirety of the HRTD program, because this program has a forecast capital cost in excess of $740.0 million. The Commission directs that an audit, under the direction of the Commission, be carried out with respect to the HRTD program, once the program is fully complete. The Commission will provide specific details regarding the audit scope, audit plan, selection of the independent auditor, and materiality limit in due course. Considering that this audit will be for the entirety of the HRTD program, capital additions for the HRTD program in each year of 2011, 2012, 2013 and 2014 will be approved as placeholders, until the audit is complete.

59. ATCO Electric's response to the direction included the following:

> There have been delays in having the HRTD expenditures included in rate base resulting from the AUC direction to first complete a cost and performance audit of the entirety of the HRTD program. Given these circumstances, and the desire to expedite the approval process for the HRTD expenditures, AET proactively engaged an independent auditor, Protiviti to complete a Cost and Performance Audit of the HRTD program.
> ….

[22] Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.
[23] Decision 2014-167: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application Compliance Filing, Proceeding 2904, Application 1610056-1, June 12, 2014.
[24] Decision 2014-283: ATCO Electric Ltd., 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances, Proceeding 2683, Application 1609720-1, October 2, 2014.

> AET submits that the audit as conducted by an independent auditor, Protiviti be used by the AUC in response to the AUC Decision 213-358, Direction 58 and further, the capital additions for the HRTD Project for the years 2011, 2012 and 2013 be approved.

60. In response to ATCO Electric's submission on compliance with Direction 58, the CCA filed a motion[25] which stated:

> 37. The CCA submitted that the audit provided by ATCO Electric had a number of deficiencies and only included costs up to December 31, 2013, contrary to the direction of the Commission. Further, the Commission was to direct and control the conduct of the audit, including the details of the audit scope, audit plan, selection of the independent auditor and the materiality limit. For these reasons, the CCA submitted the audit should be removed from evidence.

61. The Commission issued a ruling[26] with respect to ATCO Electric's response to Direction 58 on the HRTD audit which provided as follows:

> 50. The Commission considers that the contents of the HRTD audit, as filed by ATCO Electric in response to the direction from Decision 2013-358, is likely of minimal relevance to the current GTA proceedings. The Commission acknowledges that ATCO Electric may build its case before the Commission using whatever evidence it sees fit and for that reason, will not remove the HRTD audit from the record of this proceeding at this time. However, the Commission wishes to clarify that it will decline, in this proceeding, to evaluate the sufficiency of the audit with respect to its compliance with the requirements of Direction 58 of Decision 2013-358. The Commission will, likewise, not consider the question of what party will ultimately bear the cost of the audit. Parties are encouraged to bear this in mind when conducting their review and analysis of the evidence in this proceeding.
>
> 51. In Decision 2013-407,[27] the Commission ordered AltaLink to conduct an independent audit on its Southwest Transmission Development project to be able to make a final prudence determination about the project. Consistent with the treatment afforded AltaLink with the Southwest Transmission Development project, the Commission finds that the HRTD project audit should not be included in this subsequent GTA filing but should be considered in a separate proceeding, either by reopening the GTA that gave rise to the audit direction or in a newly instituted, separate proceeding
>
> 52. For the above reasons, ATCO Electric is directed to file the HRTD audit, which was submitted in the current application, as part of a proceeding the Commission will be establishing in due course to address the audit, as detailed in Direction 58 of Decision 2013-358.

62. In the above ruling, the Commission determined that the HRTD audit, prepared under ATCO Electric's direction and submitted with its application, would not be evaluated in the current proceeding as to its compliance with Direction 58. The Commission also stated that no decision would be made in the present proceeding as to which party would bear the cost of the audit. ATCO Electric is reminded that Direction 58 remains outstanding as does the direction in

[25] Exhibit 20272-X0168, CCA motion, paragraphs 14-28, PDF pages 4-8.
[26] Exhibit 20272-X0182, Commission ruling on CCA motion, paragraphs 50-52, PDF page 10.
[27] Decision 2013-407: AltaLink Management Ltd., 2013-2014 General Tariff Application, Proceeding 2044, Application 1608711-1, November 12, 2013.

the above ruling requiring that ATCO Electric file its HRTD audit as part of a future proceeding. ATCO Electric is directed to file the HRTD audit with its forthcoming transmission deferral account application for the HRTD project.

4 Terms and conditions of service

63. As part of its application, ATCO Electric filed a copy of the terms and conditions of service under which it operates[28] and noted that they were approved in Decision 2010-116.[29] It stated that no changes to these terms and conditions were being proposed in the current application.[30]

64. In response to a Commission IR, ATCO Electric stated that the AESO is in the process of completing a comprehensive review and comparison of authoritative documents and the language in TFO terms and conditions of service to determine whether all such terms and conditions are still required and the timing and process to transition to language equivalent to that in an AESO authoritative document. The AESO will advise the Commission once the review and transition is complete.[31]

Commission findings

65. In paragraph 19 of Decision 2010-116, the Commission stated:

> 19. In consideration of AE and EPC's participation in the development of the TFO T&Cs and its awareness and participation in the subsequent Commission approval processes thereto and as neither of these parties filed a SIP in this proceeding, the Commission confirms that the final T&Cs filed by AltaLink for the Second Refiling will apply to AE and EPC.[32]

66. The terms and conditions of service included in Attachment 1 of Section 3 of the application are the same as those approved in Decision 2010-116, and recognizing that no parties raised any objections to continuing with these, the Commission approves the continuation of the terms and conditions of service as filed in Attachment 1 of Section 3 of the application.

5 Forecasting methodology and key assumptions

5.1 Manpower

5.1.1 FTEs

67. ATCO Electric has applied for approval of the following forecast FTE levels for each of 2015, 2016 and 2017:

[28] Exhibit 20272-X0002, application, Attachment 3.1, PDF pages 295-324.
[29] 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.
[30] Exhibit 20272-X0002, application, PDF page 287.
[31] Exhibit 20272-X0284, response to IR AET-AUC-2015JUN08-030, PDF pages 733-734.
[32] Decision 2010-116, paragraph 19.

Table 3. Summary of forecast complement for test period

Description	Test period		
	2015	2016	2017
Schedule of transmission manpower (FTEs) - Schedule 5-5 (1)			
Complement - 2015-2017 GTA forecast - permanent	944.6	868.6	890.4
Complement - 2015-2017 GTA forecast - temporary	32.6	31.4	30.5
Complement - 2015-2017 GTA forecast - total	977.2	900.0	920.5 (3)
Schedule of corporate manpower (FTEs) - Schedule 25-5 (1)			
Complement - 2015-2017 GTA forecast - permanent	276.8	254.1	255.3
Complement - 2015-2017 GTA forecast - temporary	5.2	5.9	5.7
GTA Complement - 2015-2017 GTA forecast - total	282.0	260.0	261.0
Schedule of total company complement			
Complement - 2015-2017 GTA forecast - permanent	1,221.4	1,122.7	1,145.7
Complement - 2015-2017 GTA forecast - temporary	37.8	37.3	36.2
Complement - 2015-2017 GTA forecast – total (2)	1,259.2	1,160.0	1,181.5

Source:
(1) Exhibit 20272-X1101, schedules 5-5 and 25-5.
(2) Exhibit 20272-X1069.
(3) The Commission observes ATCO Electric has hard-coded this value into the referenced exhibits.

68. In its argument, the RPG provided a table summarizing and comparing each update to FTE forecasts that was filed in the proceeding. The RPG's Table 6-1 is reproduced below.[33]

[33] Exhibit 20272-X1297, RPG argument, paragraph 210.

Table 4. RPG summary of FTE forecasts by application update

O&M FTEs					
	Mar 2015	May 2015	Oct 2015	Dec 2015	Feb 2016
2015	392.1	392.1	322.6	302.8	321
2016	437.2	437.2	381.9	362.7	372.5
2017	439.6	439.6	402.6	383.8	393
Capital FTEs					
	Mar 2015	May 2015	Oct 2015	Dec 2015	Feb 2016
2015	957	957	951.3	792.3	938.2
2016	950.8	950.8	810.5	741.3	758.4
2017	963.1	963.1	816.1	749.2	759
Total FTEs					
	Mar 2015	May 2015	Oct 2015	Dec 2015	Feb 2016
2015	1349.1	1349.1	1273.9	1095.1	1259.2
2016	1388	1388	1192.4	1104	1130.9
2017	1402.7	1402.7	1218.7	1133	1152

Source: Exhibit 20272-X1297, paragraph 210.

69. In addressing the information contained in this table, the RPG observed that ATCO Electric's forecasted O&M FTEs for 2015 dropped to 321 as at February 23, 2016, but subsequently increased to 393 by the end of 2017. The cumulative result of these updates was that ATCO Electric's final forecasted O&M FTEs for 2015 returned to their originally forecasted level of 392.1.[34]

70. The RPG expressed concerns regarding the significant increase in both 2015 O&M FTEs and 2015 capital FTEs that occurred between the December 2015 update and the February 2016 update. Forecasted O&M FTEs were shown to increase by 18.2 and forecasted capital FTEs increased by 145.9. The RPG also identified an apparent disconnect between a reported December 2015 head count of 941 and a reported number of 1,259.2 FTEs, as reflected in ATCO Electric's GTA schedules. The RPG asserted that it is not clear exactly how many FTEs are required for ATCO Electric to meet its statutory obligations based on the utility's response to IR AET-RPG-2016APR07-002(d),[35] which sought further clarification of information provided in response to Undertaking 39.[36]

71. The RPG stated that it had no confidence in ATCO Electric's forecast FTE levels which rise dramatically from a reported year-end 2015 head count of 941 to a forecast FTE level of 1,152 in 2017. The RPG claimed that the utility's 2015 headcount of 941 suggests that, as of December 31, 2015, it required only 941 individuals to complete the required work. It contrasted

[34] Exhibit 20272-X1297, RPG argument, paragraph 211, PDF page 70.
[35] Exhibit 20272-X1286, response to IR AET-RPG-2016APR07-002(d), PDF page 10.
[36] Exhibit 20272-X1297, RPG argument, paragraph 212, PDF page 80.

this information with ATCO Electric's forecast FTE levels for 2016 and 2017, increase dramatically, reaching 1,152 in 2017.[37]

72. The RPG recommended that the Commission approve a forecast of only 941 FTEs for 2015, including 321 O&M FTEs, and direct ATCO Electric to maintain that same level for 2016. The RPG stated that this figure is consistent with the average of the November 30, 2015 and December 31, 2015 headcount, and presumably represents what ATCO Electric considered to be the level necessary to meet its statutory duties in the last two months of 2015. The RPG also recommended that the Commission direct ATCO Electric to provide a detailed reconciliation of all applied-for FTEs, relative to both actual FTEs and head count in 2015, and to list each FTE, the title, fraction of the year the position was filled, and the fraction of the position that is capital as opposed to operating (both forecast and actual).[38]

73. ATCO Electric argued that its staffing strategy has remained consistent with its past practice and that it has always attempted to "right-size" its organization to complete the required work in any given year for capital, operations and maintenance and support activities.[39] It submitted that the economic downturn in Alberta had resulted in the delay or cancellation of two major system projects and a number of customer projects that had previously been direct assigned to it. The utility explained that these factors had resulted in a new base level of project work scheduled for completion in the test years.[40]

74. ATCO Electric explained that it develops its FTE requirements using its "activity-based" budgeting approach. It submitted that the decline in capital projects during the second and third quarters of 2015 necessitated revisions to the GTA, including a reduction in FTEs. ATCO Electric submitted that its updated FTE forecasts should be accepted, as filed.[41]

75. In addressing the RPG's concern regarding the increases in FTEs between the December 2015 and February 2016 updates, ATCO Electric explained that the change results from including the full year impact of the 2015 workforce reductions in the December 2015 filing, as opposed to prorating it for one month.[42] ATCO Electric further clarified that the 941 headcount number represents individuals, whereas the FTE schedules include impacts from previous years and any workload allocation changes. Accordingly, ATCO Electric submitted that the comparison the RPG was attempting to make was invalid.[43]

Commission findings

76. The Commission rejects the RPG's recommendation to approve only 941 FTEs for 2015 and 2016. Relying on the December 31, 2015 headcount would exclude positions and that portion of FTEs that had been part of the company prior to the last month of the year.

37 Exhibit 20272-X1297, RPG argument, paragraph 213, PDF page 80.
38 Exhibit 20272-X1297, RPG argument, paragraphs 215-216, PDF page 81.
39 Exhibit 20272-X1298, ATCO Electric argument, paragraph 56, PDF page 30.
40 Exhibit 20272-X1298, ATCO Electric argument, paragraph 57, PDF page 31.
41 Exhibit 20272-X1298, ATCO Electric argument, paragraph 59, PDF page 32.
42 Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 44, PDF page 24.
43 Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 45, PDF page 24.

77. ATCO Electric, in its O&U filing, advised as follows:[44]

> 12. As indicated in AET-CCA-092, AET has not changed the vacancy rate applied to its updated 2016 and 2017 FTE and labour cost forecast. However, given that AET is not anticipating the hiring of additional staff in the remainder of 2015 due to the current economic climate, and also because the current forecast for 2015 is reflective of AET's recent information about existing staff levels which incorporates actual vacancies, for 2015 AET has assumed a further vacancy factor of 0%. Vacancies that have been directly incorporated into the 2015 FTE and labour cost forecast will appear as FTE adds in 2016.

78. The Commission understands the above statement to mean that ATCO Electric considered itself to be fully staffed, with no vacant positions, as of year-end 2015. Given this, the Commission directs ATCO Electric to use its 2015 actual FTEs as the approved complement for 2015.

79. As noted above, the RPG recommended that the Commission direct ATCO Electric to provide a detailed reconciliation of all applied-for FTEs relative to actual FTEs and head count for 2015. However, most of the requested information is already on the record of this proceeding with only the 2015 actual FTE information not being provided.[45]

80. The Commission identified in ATCO Electric's response to IR AET-AUC-2015JUN08-17(i) - February 23 Update, Exhibit 20272-X1069, that the O&M and capital allocation for the FTE forecast and the removal of forecast FTEs as a result of the workforce reduction did not match. This issue was canvassed in a discussion that occurred at the oral hearing between Commission counsel and the ATCO Electric witness.[46]

> Q. MR. FINN: And now I believe this next question is going to be for Mr. Jansen again. Now, sir, can you bring up Exhibit 1069, please. And what that is is a position listing document dated February the 23rd, 2016, and it forms an update to AET-AUC-2015JUNE08-17(i).
>
> A. MR. JANSEN: I have that.
>
> Q. Thank you. And now, Mr. Jansen, this is just another one, a bit of a tracing exercise. The Commission just needs some help navigating this document. So, Mr. Jansen, it appears to the Commission that within this document there are some identified workforce reductions that don't appear to exactly match the position that the reductions are supposed to be occurring in. And if I can take you to -- as an example, if you go to page 2 of 35 of the hard copy, so that will just be the second page of the listing, and under about midway down the page –

And on page 1389

> ……..
>
> Q. I see. Okay. Thank you. And so, Mr. Jansen, if the Commission were to note as other examples in this same document where there would be that apparent mismatch, reduced

[44] Exhibit 20272-X0604, ATCO Electric O&U filing, paragraph 12, pages 7-8 of 42.
[45] Exhibit 20272-X1069, response to IR AET-AUC-2015JUN08-017(i).
[46] Transcript, Volume 8, pages 1388-1391.

the position by .8 of an FTE in capital and .2 of an FTE in O&M. Is that -- is that right? Do we have that right?

A. MR. JANSEN: So you're looking under director, regulatory and controller, executive assistant?

Q. It would be --

A. MR. JANSEN: Or are you looking at – under Human Resources?

Q. Yes. The cost centre that I have here is Human Resources Capital?

A. MR. JANSEN: Okay.

Q. And then there's director, human resources, HS&E and facilities. And then there are two entries for executive assistant. Do you see that?

A. MR. JANSEN: Yeah, so this is more of a rounding thing, I believe. The position was primarily capital, and so only the capital part was impacted using only one month. And then a full position is gone in 2016 and '17. So because the position is basically 80 percent capital, 20 percent O&M, the O&M portion wouldn't show up for just one month on here. It would be rounded in that -- that should be a point something.

Q. I see. Okay. Thank you. And so, Mr. Jansen, if the Commission were to note as other examples in this same document where there would be that apparent mismatch, would that be the likely reason, that it's some kind of a rounding artifact?

A. MR. JANSEN: That's what I would expect, yes. Because of the fact that we're using only one-twelfth, and if a position is split, then it depends on how big the other part is.

81. The Commission previously understood that the removal of positions a month prior to the end of the year would result in a small fraction of an FTE being removed in 2015. However, it finds that Mr. Jansen's response in questioning did not address the apparent discrepancy in the O&M and capital allocations for certain FTEs removed in 2016 and 2017 as part of the workforce reduction. ATCO Electric is directed to correct the response to AET-AUC-2015JUN08-17(i) February 23 update such that the O&M and capital split for a position eliminated in the workforce reduction matches the O&M and capital split previously forecast for that position. ATCO Electric is also directed to update any impact to its O&M and capital forecast costs for the 2016 and 2017 test period as a result of these changes.

82. Once this response has been corrected, ATCO Electric is directed to identify, in the updated exhibit, the positions included in the 941 headcount in December 2015. Those positions and the FTE complement are approved as ATCO Electric's opening 2016 FTE complement.

83. The Commission finds that ATCO Electric's forecasted FTE requirements for 2016 are not sufficiently justified in the wake of its 2015 workforce reductions, notwithstanding the fact that ATCO Electric stated that it is properly staffed based on its assessment of the newly anticipated base level of work to be completed. The Commission approves only the following requested FTE additions for 2016 that are required to complete work related to cyber security and Alberta Reliability Standards as set by the AESO.

Table 5. Commission approved 2016 FTE additions

	Business need	Capital	O&M	Total
Advisor, reliability compliance	Additional workload due to Alberta Reliability Standards	-	0.5	0.5
Engineer	Additional workload due to System Growth/Cyber Security	1.1	0.5	1.5
Real time systems analyst I	Additional workload due to System Growth/Cyber Security	0.1	0.9	1.0
Technical resources technologist - qualified	Additional workload due to Alberta Reliability Standards		0.5	0.5

84. The 5.5 FTE new hire additions for 2017, from schedules 5-5.3 and 25-5.3,[47] are approved as requested.

5.1.2 Mid-year convention for salaries and associated costs

85. In its evidence, the RPG submitted that the mid-year convention should be applied to the removal of FTEs. It argued that if the mid-year convention were not used, it would provide an opportunity for a company to terminate an employee early in a given year and, nonetheless, recover a full year of salary through rates. The RPG stated that ATCO Electric had consistently applied the mid-year convention when applying for approval of FTE forecasts and that practice should be continued.[48]

86. In rebuttal, ATCO Electric stated that the RPG was "seeking to employ principles associated with the mid-year convention items affecting rate base or revenue requirement in a manner not previously seen or considered."[49] ATCO Electric specifically referred to the methodology of forecasting staff additions on a mid-year basis referenced in EUB Decision 2007-071, Section 2.4.4., PDF page 21, where the board implemented the forecast assumption that FTE additions for the test period are hired at mid-year.[50]

87. ATCO Electric stated that a historical vacancy factor has been applied to adjust the labour forecast and accounts for FTEs being "removed" from the organization, both on a voluntary and involuntary basis. In addition, it noted that employees affected by the November 2015 workforce reduction were nonetheless required during the first 11 months of 2015. It argued that the RPG's recommendation that five months' worth of these incurred costs should be disallowed is without merit because it amounts to misapplying the mid-year convention to facilitate a disallowance. ATCO Electric further stated that its adjustments to employee terminations reflect the best forecast available.[51]

88. In argument, the RPG maintained that it was appropriate to include only one half of the salaries of individuals terminated in the year, which it stated is supported by the principles that underpin the mid-year convention of recording forecast transactions for rate-making purposes.[52]

89. The RPG stated that the vacancy rate is not suited to address the forecasted removal of a position, and that if the company knows that it will have to remove an FTE from the

47 Exhibit 20272-X1101, ATCO Electric revised application, GTA schedules, 5-5.3 and 25-5.3.
48 Exhibit 20272-X0789, RPG evidence, paragraph 184, PDF page 75.
49 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 168.
50 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 169.
51 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 168.
52 Exhibit 20272-X1297, RPG argument, paragraph 217, PDF page 81.

organization, then the removal should be forecasted.[53] It also argued that the vacancy rate is intended to address events management cannot control such as employees, who over the course of year, leave the company to work for another company, unexpectedly become ill, or unexpectedly retire.[54]

90. The RPG recommended that ATCO Electric be directed to include only 50 per cent of the salaries of terminated staff in its 2015 forecast, and to provide a forecast of all other retirements in the test period consistent with application of the mid-year convention.[55]

91. ATCO Electric claimed that the RPG was misconstruing the manner in which the Commission has previously applied the mid-year convention in other circumstances and attempting to reduce the amount recoverable for the labour costs related to terminated staff. [56]

92. ATCO Electric stated that it is a normal part of its ongoing business that a certain number of employees will be terminated each year. It also argued that it had never used the mid-year convention to calculate the labour costs associated with such terminations, and that the mid-year convention had not been previously approved by the Commission for such purposes.[57]

93. ATCO Electric reiterated that the individuals affected by the workforce reduction were employed on various capital and O&M tasks throughout the term of their employment and were required to do ongoing work during the first 11 months of 2015. The costs related to their employment were actually incurred by the utility and there is simply no basis to reduce those expenditures for revenue requirement purposes.[58]

94. In reply, the RPG argued that the Commission had previously applied the mid-year convention to the forecast removal of many other items in the cost-of-service model. It submitted that if a utility knows that certain FTEs will be eliminated, then those FTEs should be removed from the revenue requirement on a mid-year basis. It claimed that if this convention were not applied, it would allow utilities to time the removal of FTEs to maximize their revenue requirement.[59] The RPG added that while the Commission has not previously applied the mid-year convention to the retirement of FTEs for ATCO Electric, neither has it ever determined such treatment to be unwarranted or without merit.[60]

95. In reply argument, ATCO Electric stated that the RPG is misusing and misapplying the mid-year convention, which has previously been accepted by the Commission in other, very different circumstances. ATCO Electric noted that this approach has not been accepted previously by the Commission in the context of terminations by ATCO Electric, despite the fact that terminations take place every year.[61]

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53 Exhibit 20272-X1297, RPG argument, paragraph 223, PDF page 83.
54 Exhibit 20272-X1297, RPG argument, paragraph 224, PDF page 83.
55 Exhibit 20272-X1297, RPG argument, paragraph 230, PDF page 85.
56 Exhibit 20272-X1298, ATCO Electric argument, paragraph 108, PDF page 52.
57 Exhibit 20272-X1298, ATCO Electric argument, paragraph 108, PDF page 52.
58 Exhibit 20272-X1298, ATCO Electric argument, paragraph 110, PDF pages 52-53.
59 Exhibit 20272-X1307, RPG reply argument, paragraph 213, PDF page 62.
60 Exhibit 20272-X1307, RPG reply argument, paragraph 214, PDF page 62.
61 Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 98, PDF page 47.

Commission findings

96. The Commission considers there are two discrete issues to be decided in its evaluation of ATCO Electric's FTE forecasts. The first is whether the positions that ATCO Electric terminated in 2015 should be reflected in a mid-year FTE complement. The second is whether it is reasonable to require a utility that intends to remove FTEs from its test period complement to forecast the removal of those positions on a mid-year basis.

97. In the EPCOR Distribution & Transmission Inc.'s 2012 tariff application, Proceeding 1596, the Commission defined vacancy rates as follows:

> 57. The vacancy rate represents a ratio of the number of vacant FTE positions compared to the total approved FTEs for a given period, and it is applied as a reduction against the forecast labour expenses to reflect that a certain number of positions will be vacant in the given period, thereby reducing the forecast labour expenses. The higher the vacancy rate used in the forecast period, the greater the reduction applied against the total potential labour dollars for the proposed FTE level.[62]

98. The Commission determines the approved FTE complement, and the recovery of these costs through the revenue requirement, in a two-step process. First, the Commission approves the forecast FTE complement and the number of people required to perform the forecast work. Next, it applies the utility's vacancy rate (representing the utility's normal turnover rate, including voluntary and involuntary departures) and adjusts for the market conditions that may increase or decrease the expected turnover.

99. The Commission considers that the annual vacancy rate represents the percentage of the approved FTE complement that is expected to be vacant during the year.

100. The Commission recognizes that ATCO Electric has filed numerous updates to forecasts for 2015, reflecting both updated costs and FTE complements. The work completed on projects in 2015 that occurred beyond the mid-year point will be included in actual costs when ATCO Electric files an application to settle its 2015 deferral balances. The Commission directs ATCO Electric to use its actual 2015 FTEs as the approved forecast FTE complement for that year. The Commission rejects the RPG's recommendation to direct ATCO Electric to revise its reported mid-year complement for 2015 to reflect terminations that occurred throughout the year. The Commission will assess the prudency of direct assigned project capital expenditures, including the prudency of labour costs related to the terminated positions, in a future DACDA filed by ATCO Electric.

101. The Commission is of the view that a utility should apply the mid-year convention to the removal of an FTE in the year of its forecasted removal if the utility is not expecting to fill the position through promotion or an external hire going forward. This treatment should be applied regardless of the underlying reason for the FTE's removal. The Commission considers that such treatment reflects reciprocal application of the mid-year convention used when the Commission approves a forecast addition to a utility's FTE complement. The Commission directs ATCO Electric to apply the mid-year convention to any and all FTE removals and associated costs forecasted for 2016 and 2017.

[62] 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, paragraph 57.

5.1.3 Vacancy rates

102. ATCO Electric has applied for the following vacancy rates as shown in the table below:

Table 6. ATCO Electric forecast vacancy rates

	2015	2016	2017
Transmission Direct O&M	0.00	2.50	2.50
Other O&M	0.00	2.50	2.50
Capital	0.00	2.50	2.50

Source: Exhibit 20272-X1100, Table 1.7 Key Assumptions, page 1-26. PDF page 26.

103. ATCO Electric stated in its O&U filing that it did not anticipate hiring additional staff in the remainder of 2015 due to the economic climate being experienced. It also submitted that its current forecast for 2015 reflects recent information about existing staff levels, which incorporates actual vacancies. The utility assumed a vacancy factor of zero per cent for 2015.[63]

104. ATCO Electric stated that the vacancy rates of the past several years were not indicative of vacancy rates in 2016 and 2017. ATCO Electric expects that employee turnover will be lower in 2016 and 2017, resulting in fewer vacant positions, and that the time to hire will decrease with an increase in unemployed people looking for work. ATCO Electric stated that its calculation of a 2.5 per cent vacancy rate was based on a combined assumption of a 30 per cent reduction in turnover and a 25 per cent reduction in the time required to hire.[64]

105. The RPG recommended that the Commission direct ATCO Electric to revise its 2015 and 2016 vacancy rates to the rates previously approved in Decision 2013-358.[65]

106. In argument, ATCO Electric stated that its forecast vacancy rate of 2.5 per cent for 2016 and 2017 is reasonable because it reflects current economic conditions and the fact that it made a significant workforce adjustment near the end of 2015.[66]

Commission findings

107. As discussed in Section 5.1.1 above, the Commission directed ATCO Electric to use 2015 actual FTEs as its 2015 FTE approved complement. The use of 2015 actuals reflects zero vacant FTEs for 2015. Accordingly, a vacancy rate of zero per cent for 2015 is approved.

108. The Commission finds it reasonable to expect a lower level of employee turnover in the current economic environment and, therefore, accepts ATCO Electric's argument in support of a 2.5 per cent vacancy rate for 2016 and 2017. ATCO Electric's vacancy rates are approved as filed.

5.1.4 Severance costs

109. ATCO Electric notified the Commission in a letter dated November 30, 2015 that it had undertaken an organizational change that resulted in a significant workforce reduction.[67] In

[63] Exhibit 20272-X0604, ATCO Electric O&U filing, page 7 and 8 of 42.
[64] Exhibit 20272-X1100, revised application, paragraph 54 PDF page 27.
[65] Exhibit 20272-X1297, RPG argument, paragraph 230, PDF page 85.
[66] Exhibit 20272-X1298, ATCO Electric argument, paragraph 55, PDF pages 29-30.
[67] Exhibit 20272-X0691, ATCO Electric organizational impact correspondence.

response to a Commission IR, ATCO Electric disclosed that it was seeking to recover a total of $12.6 million in severance costs related to the termination of approximately 337 positions in 2015.[68] In its evidence, the UCA provided trend analysis to illustrate that ATCO Electric's O&M FTEs were increasing at a rate greater than the rate of growth in assets, and the number of capital FTEs relative to the level of capital expenditures per year continued to grow.[69] The UCA, based on its analysis, suggested that ATCO Electric is over-staffed and recommended that severance related to O&M staff be removed from revenue requirement.[70]

110. The RPG observed that severance paid to employees was above the minimum amount required by the *Alberta Employment Standards Code* (AESC).[71] [72] In Exhibit 20272-X0790, Attachment 1 – Calculation of Severance Costs, the RPG calculated the cost of severance to the terminated employees using the AESC. The schedule demonstrates that ATCO Electric paid $10.1 million more than what the AESC would require.[73] The RPG admitted that amounts awarded by the courts, based on common law, may exceed what is required to be awarded under the AESC.[74]

111. In rebuttal, ATCO Electric stated that the AESC represents only a minimum standard, and that the AESC may be superseded by Canadian common law, pursuant to which employers are required to provide a reasonable notice of termination of employment based on certain factors. ATCO Electric stated that it follows these legal principles with respect to legislated employment standards and common law requirements whenever a permanent employee reduction takes place. It also stated, by way of clarification, that severance payments for in-scope employees are governed by the express terms of the Collective Bargaining Agreement (CBA).[75]

112. ATCO Electric took issue with the RPG's response to an IR in which, it stated that:[76]

> It is common practice for an employer to insert a clause within a severance agreement that requires the repayment of severance by the terminated employee if they secure equivalent employment within a shorter period of time than expected in the payment of severance. As AET is not forecasting a reimbursement of severance from the hundreds of employees terminated, it is very likely that AET did not insert such a clause into its own severance payment agreements.

113. ATCO Electric responded in its rebuttal argument that the RPG's claim in this regard is incorrect and unsupported. It added that the practice does occur but is far from common.

114. The RPG argued that ATCO Electric did not take the necessary steps to ensure that the severance contracts were fair to customers. It added that severance is only intended to provide an employee compensation until that employee can reasonably be expected to secure other employment. The RPG suggested that companies could include a clause in their severance

68 Exhibit 20272-X0735, response to IR AET-AUC-2015DEC30-012(b).
69 Exhibit 20272-X0777, UCA evidence, Q22 through A29, pages 16-19, PDF pages 17-20.
70 Exhibit 20272-X0777, UCA evidence, A32, page 20, PDF page 21.
71 Exhibit 20272-X0789, RPG evidence, paragraph 168, PDF page 70.
72 RSA 2000, c. E-9.
73 Exhibit 20272-X0789, RPG evidence, paragraph 172, PDF page 71.
74 Exhibit 20272-X0789, RPG evidence, paragraph 173, PDF pages 71-72.
75 Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 159-162.
76 Exhibit 20272-X0811, response to IR RPG-AUC2016FEB01-008.

agreements that claws back any severance paid to employees if they obtain new employment prior to the end of the period intended to be covered by the severance payment.[77]

115. The RPG recommended a 50 per cent reduction in the amount of severance ATCO Electric should be allowed to recover in revenue requirement for its failure to include a claw back clause in its severance agreements. The RPG stated that the 50 per cent represents its best estimate of the proportion of staff that would have obtained employment before the term of their severance payments expired.[78]

116. ATCO Electric submitted that its capital forecast, and particularly its direct assigned projects from the AESO, were dramatically reduced as a result of both delays in, and cancellations of, both system and customer projects previously assigned to it, and that it acted promptly to "right-size" its workforce in response to the level of work it expects to perform over the 2015-2017 test period.[79]

117. ATCO Electric submitted that, since the rates approved in its 2013-2014 GTA had already come into effect, it had no incentive to add additional FTEs beyond what had been approved unless they were actually needed. According to the utility, there was no evidence that its workforce included excessive FTEs at the start of 2015. ATCO Electric claimed that "[i]n fact, the only evidence on the record supports the opposite view that all FTEs in place prior to the workforce reductions were indeed required to complete work that [it] had forecast would be completed in 2015."[80]

118. ATCO Electric stated that it relied upon advice from both its human resources group and legal counsel in determining the proper level of termination compensation.[81] ATCO Electric provided its out-of-scope employees termination notice pay (i.e., pay in lieu of notice) in amounts that, it contends, conform to both the AESC and common law requirements.[82] In determining the required level of severance compensation for in-scope employees, ATCO Electric stated that it was bound by the terms of the CBA.[83]

Commission findings

119. The Commission finds that the severance amounts ATCO Electric awarded to employees were reasonable in the circumstances. The question for determination is whether and how much of these amounts should be approved for recovery in rates.

120. The Commission considers that while the idea of including a severance clawback clause in employment agreements, as was recommended by the RPG, may be of theoretical interest, such clauses are inherently difficult to enforce and may not be suited to all industries and situations. The RPG has not persuaded the Commission that other companies, let alone companies in the Alberta utility sector, commonly include such clauses in their standard employment agreements. The RPG's recommended disallowance of severance costs on this basis is unsupported and has been assigned minimal weight in the Commission's decision.

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77 Exhibit 20272-X1297, RPG argument, paragraph 239, PDF page 88.
78 Exhibit 20272-X1297, RPG argument, paragraph 249, PDF page 91.
79 Exhibit 20272-X1298, ATCO Electric argument, paragraph 100, PDF pages 48-49.
80 Exhibit 20272-X1298, ATCO Electric argument, paragraph 101, PDF page 49
81 Exhibit 20272-X1298, ATCO Electric argument, paragraph 104, PDF page 50.
82 Exhibit 20272-X1298, ATCO Electric argument, paragraph 106, PDF page 51.
83 Exhibit 20272-X1298, ATCO Electric argument, paragraph 105, PDF pages 50-51.

121. The Commission observes from the table below (which was compiled from evidence on the record of this proceeding) that in 2014 ATCO Electric had a higher FTE complement than what was approved in its 2013-2014 GTA application.

Table 7. ATCO Electric 2014 actual FTEs

Description	Schedule 5-5 (Transmission manpower)	Schedule 25-5 (Corporate manpower)	Total
2013-2014 GTA approved complement -permanent	1,062.5	210.3	1,272.8
Vacancy (negative) indicates higher complement than approved	(22.4)	2.8	(19.6)
2013-2014 actual adjusted complement - permanent	1,084.9	207.5	1,292.4
2013-2014 GTA approved complement - temporary	91.4	17.2	108.6
Vacancy (negative) indicates higher complement than approved	6.2	2.9	9.0
2013-2014 actual final adjusted complement - temporary	85.2	14.3	99.6
2013-2014 GTA approved complement - total	1,153.9	227.5	1,381.4
Vacancy (negative) indicates higher complement than approved	(16.3)	5.7	(10.6)
2013-2014 actual final adjusted complement - total	1,170.2	221.8	1,392.0

Source 20272-X1101, schedules 5-5 and 25-5.

122. In approving an FTE complement submitted in a GTA, the Commission assesses forecasted staffing levels including forecasted additions for the test period. Any subsequent variance between actual hires and the approved forecast is a risk borne by the utility. If the actual number of positions added exceeds the approved number, the excess costs must be borne by the utility until such time as the Commission approves an FTE complement (and the corresponding number of positions) sufficient to absorb the positions previously added in excess of approved levels.

123. It is clear from the above table that at year-end 2014 ATCO Electric had approximately 20 permanent FTEs in excess of its approved complement for that year. The utility also had approximately nine fewer temporary FTEs than approved by the Commission. The Commission has no means of determining how many employee positions were associated with the 20 excess permanent FTEs at year-end 2014 identified in the table.

124. The Commission also observes that ATCO Electric reported 1,392 total FTEs at year-end 2014 and forecasted 2015 year-end total FTEs of 1,259.2.[84] This compares to ATCO Electric's actual head count at year-end 2015 of 941.[85] In an environment where large-scale terminations are taking place, it is very unlikely, if not impossible, for headcount to exceed reported FTE levels. This is because while an FTE represents the fraction of a year an employee spends (or is forecast to spend) performing a work function, headcount values are discrete measures of the number of individuals employed at a given point in time.

125. ATCO Electric provides services to other ATCO Ltd. subsidiaries and affiliates including ATCO Power, ATCO Energy Solutions, and Alberta PowerLine. As confirmed by ATCO

[84] Exhibit 20272-X1101, ATCO Electric revised application, schedules 5-5 and 25-5.
[85] Exhibit 20272-X1286, response to IR AET-RPG-2016-APR07-002.

Electric in responses to Commission information requests, it contributed, or forecasted to contribute, all or portions of, 135 positions to ATCO Energy Solutions, 177 positions to ATCO Power [86] and 42 positions[87] to Alberta PowerLine in 2015. ATCO Electric produced a list of positions terminated as part of workforce reductions in 2015 in response to an information request.[88] A comparison of the positions shared with the affiliates identified above to the job classes that were included in the list of terminated positions shows that many of the positions shared similar job functions.

126. Whenever ATCO Electric provides services to an affiliate, it should, at a minimum, be kept whole so as to leave it indifferent to whether the employee resides in the affiliate to which it is providing services or resides in ATCO Electric itself. In the case of severance, transmission rate payers should not be responsible for the entirety of the severance costs that relate to employees who actually provided service or were forecasted to provide services to an affiliate. There was little or no evidence in this proceeding addressing which corporate entity, as between ATCO Electric and any of its affiliates that received services from it, is responsible, whether in whole or in part, for the severance costs of ATCO Electric employees providing (or forecasted to provide) services to these same affiliates when their positions were eliminated in 2015.

127. There is support in the following exchange between Commission counsel and ATCO witness, Mr. DeChamplain, for the claim that ATCO Electric employees who were terminated actually did, or were forecasted to, provide labour services to affiliate companies:

> Q. And so, sir, as you just referenced a couple of moments ago, if we look to the total FTE requirements at the bottom of that table, which is labelled "Summary of WFMAC FTE Requirements," we see the revised number, and it goes down from an originally forecast value of 54.63 to an updated forecast value of 26.20. Do you see that, sir?
>
> A. MR. DECHAMPLAIN: Yes, sir.
>
> Q. So in terms of the original forecast of 54.63, were the required FTEs actually hired at that level?
>
> A. MR. DECHAMPLAIN: ATCO Electric Transmission was essentially under a hiring freeze throughout 2015. So there were -- it came up earlier in the proceeding -- there were some targeted hires in 2015, and that was more to replace some voluntary turnover. So those resources weren't -- sorry, ATCO Electric Transmission didn't go out into the market to procure an additional 54 people to add to its complement that it would intend on using on the West Fort McMurray project.
>
> Q. So essentially what the forecast was, then, was a forecast required reallocation of existing resources; is that right?
>
> A. MR. DECHAMPLAIN: Correct. And in one of the AUC IRs, it goes through all of the positions and the percent that would have been forecast to provide services for the West Fort McMurray project, and they would have been forecasted and charged to that line item and not included in the revenue requirement ask in the application.

[86] Exhibit 20272-X0623, response to IR AET-AUC-2015OCT16-005, Attachment 1.
[87] Exhibit 20272-X0623, response to IR AUC-AET-2015OCT16-004(h), Attachment 1, page 1 of 3.
[88] Exhibit 20272-X0735, response to IR AET-AUC-2015DEC30-12(b).

Q. Thank you. And in terms of the surplus FTEs -- I'm going to call them that, the ones that were no longer required for 2015 in accordance with the updated forecast -- where are they now within ATCO Electric Transmission? What tasks are they doing?

A. MR. DECHAMPLAIN: When we approached the November workforce reduction, that reduction would have been done, you know, with all of the workforce requirements. I mentioned yesterday that a handful of a hundred percent employees -- I believe there's, you know, in the range of one to two dozen employees which are a hundred percent allocated -- the rest of the individuals have those slivers of time which are forecasted and charged to the project.

For any previously hundred-percent dedicated individuals, they would have been factored into the overall resource pool that ATCO Electric had, and it would have compared that resource pool to implement the lower direct-assigned capital program going forward. And would have been taken into account or rationalized during that November workforce reductions.

The -- the other slivers of time that get reallocated, those people would be working on capital projects, indirect capital overhead, but the entire quantum would have been rolled up in that review of the overall resources required on a go-forward basis.[89]

128. In a discussion between Commission counsel and ATCO Electric witness, Mr. Jansen, the witness was questioned about the February 23, 2016, update to Commission information request AET-AUC-2015JUNE08-17(i), which provided a list of positions and their forecasted FTE levels.[90] The Commission was interested in obtaining a clarification to an earlier explanation from ATCO Electric regarding terminated employees.

Q. I see. Thank you. And now, Mr. Jansen, if I can just bring you down to the very bottom of this sheet, please. And the last row that we would be looking at is Add Back Forecasted Terminations?

A. MR. JANSEN: Yes.

Q. Okay. And there's an asterisk after that entry. And if I go down to the notes it says: (as read) "Terminations forecasted in 2016 and 2017 occurred in 2015." Do you see that, sir?

A. MR. JANSEN: Right. Yes.

Q. And now, so in looking at this document, it appears to the Commission that AET is adding back terminations that were forecasted in 2015 -- or 2016 and 2017 but occurred in 2015. Is that right?

A. MR. JANSEN: So what we had done -- this is actually -- when I was referring earlier about forecasting terminations, this is what I was actually referring to was these amounts.

So I'll find out about the 2014 adjustments. But the -- what we had done in 2015 is we knew projects were going to be coming to a close, and we had forecast in 2016 that we would be terminating positions at some point. Whether they were going to be terminated or with 80 positions could we absorb them elsewhere in the organization, through attrition, that sort of thing, so that's what that represents. And since the decrease -- the

[89] Transcript, Volume 8, pages 133,1 line 18 to 1333 line 22, Questioning from Commission counsel
[90] Exhibit 20272-X1069, response to IR AET-AUC-2015JUN08-017(i).

> workforce reduction took a much bigger chunk out of the organization and it was already adjusting for the capital projects that were going to reduce and later on we knew further projects needed to be reduced, this forecast of further terminations in 2016 was no longer required.
>
> Q. I see. Thank you.[91]

129. It is clear from the above excerpt from the hearing transcript that ATCO Electric had forecast to remove more than 80 positions in 2016 and 2017 from its FTE complement through transfers to other ATCO companies, and other means of attrition. It is also clear that, given the unexpected scope and severity of the downturn in the Alberta economy that precipitated the significant workforce reduction in late November 2015, ATCO Electric determined that there was no longer any need (even of a short-term nature) for the above mentioned positions nor any benefit to the utility in waiting an additional year or two before eliminating them. Instead, ATCO Electric simply revised the date on, and means by, which these surplus positions were eliminated. The Commission therefore finds, on the basis of the above testimony, that a material percentage of the utility's total claim for the recovery of severance payments relates to the cost of terminating surplus employees that ATCO Electric had earlier determined it would not, in any event, retain beyond 2016 or 2017.

130. ATCO Electric employees held the eliminated positions. ATCO Electric would bear severance costs flowing from their termination in the normal course. The existence of a shared services (or any other) affiliate relationship does not change this obligation on the part of ATCO Electric. The Commission considers that ATCO Electric, in setting charges for services provided to affiliates, would have been required to make allowance for recovery of potential severance costs in order to meet its obligations under Section 3.3.4 of the ATCO Inter-Affiliate Code of Conduct.

131. Had labour rates for services provided by ATCO Electric to any of its affiliates included a component for potential future severance costs, there would be no need for ATCO Electric to seek compensation for such severance costs in the present application. If labour rates incorporated no provision for potential severance costs, then these costs must be borne by ATCO Electric and not its ratepayers.

132. The Commission considers it reasonable to conclude that most, if not all, of the severance costs being claimed by ATCO Electric in its application relate to payments made to employees terminated from permanent (as opposed to temporary) positions. As noted above, ATCO Electric entered 2015 with 20 permanent FTEs in excess of its most recent Commission-approved FTE complement.

133. ATCO Electric has provided the Commission with inadequate support to justify full recovery of its claimed severance costs in rates. ATCO Electric ended 2014 and started 2015 with approximately 20 permanent FTEs in excess of Commission-approved levels for 2014. The utility also acknowledged during the oral hearing that it eliminated more than 80 positions at the end of 2015 that had been assigned to provide services to affiliates in 2016 and 2017 and were originally forecasted for termination by the end of 2017. The information provided by ATCO Electric leaves it unclear whether the 20 surplus FTEs at the beginning of 2015 included any of the above positions. Consequently, the Commission is unable to determine what proportion of

[91] Transcript, Volume 8, page 1390, line 23 to page 1392, line 15.

the severance costs for the 337 positions eliminated in 2015 should be ATCO Electric's to bear and what proportion should be recovered from ratepayers. This notwithstanding, and for all of the reasons provided above, the Commission is not persuaded that ATCO Electric has demonstrated that the full amount of severance costs claimed should be borne by ratepayers. Instead, the Commission considers it reasonable, based on the evidence in this proceeding, to allow ATCO Electric to recover $8.2 million, representing 65 per cent of the total severance costs it has claimed.

5.1.4.1 Treatment of severance costs – capitalize or expense

134. In response to a Commission IR, ATCO Electric stated that it recorded the severance costs in accordance with IFRS, and that these severance costs were expensed in the year they occurred (i.e., 2015). ATCO Electric provided an alternate method to recover the severance costs from customers, which is to recover them in three equal amounts over the three year test period.[92]

135. The RPG claimed that ATCO Electric had misinterpreted International Accounting Standard (IAS) 16 – Property, Plant and Equipment, by expensing severance costs, and that IAS 16.20 was not intended to prohibit the capitalization of employee benefits. The RPG submitted that IAS 16, paragraphs 16 and 17, requires the capitalization of employee benefit costs.[93]

136. The RPG also pointed to AUC Rule 026: *Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards*, and noted that the capitalization of termination benefits is not one of the exemptions identified in the rule. In its view, IAS 16 and 19 clearly state that termination benefits are an employee benefit that must be capitalized under IFRS. The RPG recommended that ATCO Electric be directed to capitalize the portion of the severance costs that pertain to capital FTEs.[94]

137. In rebuttal, ATCO Electric provided an extract from IAS 16 Property Plant and Equipment. ATCO stated that IAS 16 allows employee benefits arising directly from the construction of an asset to be included in the cost of the asset. It argued, however, that because termination benefits are paid in exchange for the termination of employment rather than for the construction of an asset, there is no future economic benefit attributable to those costs and, hence, they cannot be capitalized.[95]

Commission findings

138. In its rebuttal, ATCO Electric provided the following excerpt from IAS 16 Property Plant and Equipment:[96]

> 16 The cost of an item of property, plant and equipment comprises:
>
> (a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
>
> (b) <u>any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.</u>

[92] Exhibit 20272-X0735, response to IR AET-AUC-2015DEC30-007(e).
[93] Exhibit 20272-X0789, RPG evidence, paragraph 177, PDF pages 73-74.
[94] Exhibit 20272-X0789, RPG evidence, paragraph 179, PDF pages 74-75.
[95] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 166-167.
[96] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF age 166.

[emphasis added]

(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

17 Examples of directly attributable costs are:

(a) costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment; [emphasis added]

(b) costs of site preparation;

(c) initial delivery and handling costs;

(d) installation and assembly costs;

(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

(f) professional fees. [emphasis added]

139. Based on its consideration of IAS 16, the Commission finds that ATCO Electric's interpretation of the accounting principles applicable to a determination of whether severance costs may be capitalized or expensed is reasonable. The Commission approves the expensing of $8.2 million in severance costs related to workforce reductions in 2015.

5.2 Compensation

5.2.1 Labour escalation

140. ATCO Electric has applied for labour inflation for the test periods as follows:

Table 8. Summary of proposed labour inflation

	2015	2016	2017
Labour – In-scope	3.50	3.75	3.75
Labour – Out-of-scope	0.30	3.75	3.75

Source Exhibit 20272-X1100, Table 1.7 Key Assumptions, page 1-26, PDF page 26.

141. The Commission will address the in-scope and the out-of-scope inflation rates separately below.

5.2.1.1 In-scope escalation

142. ATCO Electric applied for inflation increases of 3.5 per cent, 3.75 per cent, and 3.75 per cent for the years 2015, 2016 and 2017, respectively. ATCO Electric explained that the requested in-scope inflation rates for 2015 and 2016 reflect those applicable to the last two years of a three-year agreement concluded with the Canadian Energy Workers Association (CEWA) on

October 7, 2014. The agreement, which provides for inflation increases of 3.5 per cent in 2014, 3.5 per cent in 2015 and 3.75 per cent in 2016, will expire on December 31, 2016.[97]

143. The RPG observed that the collective agreement between ATCO Electric and CEWA does not include an inflation adjustment clause to address the possibility of an economic downturn.[98]

144. The RPG argued that collective agreements are not tested for reasonableness in the same way that forecasts are tested in a GTA. With the passage of time, for example, the inflation rates built into multi-year collective agreements may no longer reflect current market conditions or the interests of ratepayers.[99] Given the cyclical nature of Alberta's resource based economy, the RPG argued it would be prudent for the utility to negotiate the inclusion of "reopeners" in collective agreements that could be triggered by evidence of specified adverse economic conditions.

145. The RPG provided evidence of union wages for construction workers in Edmonton and Calgary, who it considered to be comparable to ATCO Electric's construction labour force. The RPG argued that the annual growth rate in wages for those occupations never exceeded 1.65 per cent between August 2013 and December 2015. The RPG also submitted that growth in union wage rates was unlikely in the near term given the current economic conditions in Alberta.[100] Furthermore, it was of the view that the Government of Alberta's wage freeze on non-unionized workers would likely carry over to union workers in the 2016-2017 period.[101]

146. The RPG concluded its evidence on this issue by stating:

> AET's [ATCO Electric's] union employee escalation rates were determined based on a collective agreement for a period that began before the effects of the oil price decline took their toll on the province. Their economic assumptions are therefore out of date. AET should have acted more prudently and accounted for the traditional cycle of booms and busts in Alberta. Based on actual recent escalation rates for a variety of union positions provided by Statistics Canada data, the Ratepayer Group recommends escalation rates of 0% in all three years, in line with actual escalation rates for a variety of union workers provided by Statistics Canada data.[102]

147. ATCO Electric, in rebuttal, acknowledged that its Collective Bargaining Agreement (CBA) with CEWA does not include an inflation adjustment clause or an economic trigger to reopen collective bargaining. It argued that these types of clauses are not common in the industry, and have not been common in Alberta for a long time.[103]

148. ATCO Electric confirmed that its previous negotiations with CEWA began in September of 2013 and concluded with its execution of the current CBA in October of 2014. It argued that, at the time the contract was being negotiated, there was no indication that a significant economic downturn, precipitated by a dramatic decline in oil prices, was imminent. The utility also

97 Exhibit 20272-X1100, revised application, paragraph 50, PDF page 26.
98 Exhibit 20272-X0789, RPG evidence, Appendix A paragraph 53, PDF page 157.
99 Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 55, PDF page 158.
100 Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 59, PDF page 159.
101 Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 60, PDF page 160.
102 Exhibit 20272-X0789, RPG evidence, paragraph 214, PDF pages 82-83.
103 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 173-175.

confirmed that previous CBAs with CEWA had never incorporated economic reopener clauses.[104]

149. ATCO Electric stated that it reviews all market comparators to determine market direction for the escalation of wage rates. It argued that the "Construction Trades Association" data, cited by the RPG, is not an appropriate market comparator for any utility in Alberta because of the different job skills required and the cyclical and seasonal type of work the construction trades group performs. ATCO Electric submitted that the reasonableness of the current CBA should be assessed based on the information that was available at the time it was negotiated. It also argued that its current agreement with CEWA, which provides for inflation increases of 3.5 per cent for 2014, 3.5 per cent for 2015, and 3.75 per cent for 2016, closely aligns with settlements reached by other comparator companies.[105]

150. The RPG argued that ATCO Electric was well aware of capital projects being put on hold as early as September 26, 2014, and that it was common knowledge that oil prices had been declining for more than three months.[106] The RPG submitted that it is ATCO Electric's responsibility to manage the uncertainty in conditions in labour markets, and ensure that negotiated wage rates are no higher than necessary.[107]

151. The RPG claimed that ATCO Electric had mismanaged the uncertainty over future labour market conditions at the time the CEWA agreement was negotiated. In its view, the utility had several options for managing this risk, including (1) delaying the ratification of the collective agreement to gain more information on the future trend in oil prices and Alberta labour market conditions, (2) adding a reopener clause that would be triggered if key economic indicators, including oil prices, breached certain thresholds, or (3) shortening the term of the collective agreement, none of which it pursued.

152. The RPG also pointed out that ATCO Electric had provided a table in its own rebuttal evidence showing that the most recently negotiated agreement by TransAlta settled at zero per cent inflation for both 2016 and 2017.[108]

153. The RPG ultimately recommended that the Commission approve in-scope labour inflation rates of zero per cent for all three test years to conform to the most recent utility collective agreement negotiated in Alberta by TransAlta.[109]

154. In reply, ATCO Electric reiterated that it had negotiated in good faith with CEWA to establish a three-year CBA for the period 2014 to 2016, inclusive. It claimed that the rates agreed upon both reflected the market conditions prevailing at the time and those that were forecast to occur.[110] The utility submitted that its forecast labour inflation rate of 3.75 per cent for 2017 represents its best forecast of amounts that will be payable under the CBA, and therefore should be approved as filed.[111]

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104 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 174.
105 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 174-175.
106 Exhibit 20272-X1297, RPG argument, paragraph 103, PDF page 52.
107 Exhibit 20272-X1297, RPG argument, paragraph 105, PDF page 53.
108 Exhibit 20272-X1297, RPG argument, paragraph 109, PDF page 54.
109 Exhibit 20272-X1297, RPG argument, paragraph 111, PDF page 54.
110 Exhibit 20272-X1298, ATCO Electric argument, paragraph 49, PDF pages 27-28.
111 Exhibit 20272-X1298, ATCO Electric argument, paragraph 51, PDF page 28.

Commission findings

155. In Decision 2013-358, which was issued on September 24, 2013, the Commission approved ATCO Electric's forecasted labour inflation rate of 3.5 per cent for 2014. In doing so, it made the following finding:

> 176. … The Commission finds ATCO Electric's labour inflation rate forecast for 2013 and 2014 of 3.5 per cent for both unionized and non-unionized employees to be reasonable and consistent with general trends in the economy and therefore approves a forecast labour inflation rate of 3.5 per cent for each of 2013 and 2014.[112]

156. ATCO Electric started negotiations with CEWA in the same month that Decision 2013-358 was issued. The Commission agrees with ATCO Electric that the reasonableness of the current CBA should be assessed based on the information that was available at the time it was negotiated.

157. The Commission finds that the fact that a decline in the price of oil had already been observed in Alberta by the time the CBA was concluded is not sufficient to support an allegation that ATCO Electric acted unreasonably in proceeding to implement it. It is not reasonable to assume that ATCO Electric (or any other party) could have appreciated the severity and duration of the coming shock to Alberta's economy, or its effect on wage inflation. Additionally, although the Commission received evidence that the CBA was signed October 7, 2014, it was not established on what date the negotiated wage increases were agreed to and put to member consultation and ratification. Consequently, it is not reasonable to conclude that the version of the collective agreement in existence as of that date was, in practical terms, subject to re-negotiation or revision, in any event.

158. Therefore, the Commission approves the inflation rate for in-scope employees at 3.5 per cent and 3.75 per cent for 2015 and 2016, respectively.

159. There is no CBA in place for the 2017 test year. The CBA over the periods of 2015 and 2016 saw wage inflation significantly higher than what has been experienced by other companies in Alberta over the same period. ATCO Electric provided no evidence to suggest that the 2016 rate of 3.75 per cent was representative of actual conditions in the Alberta labour market. The same applies to ATCO Electric's proposed 2017 wage inflation rate for in-scope employees. This compares to the zero per cent wage inflation rate incorporated into the collective bargaining agreement signed by TransAlta with its unionized employees for the years 2016 and 2017. In addition, the Commission notes that no evidence has been presented by any party, including ATCO Electric, to suggest that it would be reasonable to expect a return to vigorous economic growth in Alberta by 2017. Therefore, the Commission denies the requested 3.75 per cent labour inflation increase requested by ATCO Electric for 2017, and instead approves a zero per cent in-scope labour inflation rate for 2017.

5.2.1.2 Out-of-scope escalation

160. ATCO Electric updated its 2015 out-of-scope labour inflation rate to 0.3 per cent in its O&U filing. For 2016 and 2017, ATCO Electric applied for an out-of-scope labour inflation increase of 3.75 per cent in each year. ATCO Electric confirmed that this increase was the same as that incorporated in the CBA for in-scope employees for the year 2016 and was also the wage

[112] Decision 2013-358, paragraph 176.

inflation rate it was forecasting for in-scope employees for 2017. ATCO Electric submitted that these forecast wage rate increases (for in-scope and out-of-scope labour) align with current, and near term expectations for, labour market conditions in Alberta. ATCO Electric included a 2015 Total Remuneration Review study by Mercer[113] in its submissions indicating that its out-of-scope employees are currently compensated at a level that is 12 per cent below the market midpoint.

161. The RPG, in its evidence, identified several companies in ATCO Electric's peer group for the Mercer compensation study that had announced layoffs. RPG also pointed to Canadian Natural Resources, which is not in the peer group of the Mercer study, but had announced that it was cutting salaries by up to 10 per cent.[114] It also referenced the Government of Alberta's two-year wage freeze for non-unionized public service employees for 2016 and 2017.[115]

162. The RPG also provided data from Statistics Canada on wage earnings in various industries including oil and gas extraction, utilities, electric power generation, transmission and distribution (a sub-category of utilities). It submitted that its analysis of this evidence demonstrated that ATCO Electric's current ranking in the Mercer study (at 12 per cent below market median) for out-of-scope employees represents a normal compensation difference between utility out-of-scope employees and out-of-scope employees working in the oil and gas sector.[116] The RPG stated that it is unreasonable for ATCO Electric to attempt to meet the market median compensation of the comparator group of companies, as selected by Mercer, given that out-of-scope employees and contractors in oil and gas exploration and production companies have historically earned significantly more than their counterparts in the utility and transmission sectors.[117]

163. The RPG argued that the labour market ATCO Electric shares with oil and gas companies has experienced widespread layoffs and that downward pressure on wages should be expected.[118] It recommended that out-of-scope labour inflation rates of 0.7 per cent in 2015, 2.2 per cent in 2016, and 2.8 per cent for 2017, which, in its view, are consistent with the forecast Alberta Wage and Salary escalation rates by the Conference Board of Canada, be approved by the Commission.[119]

164. The RPG also argued that the Mercer report filed by ATCO Electric in its original application is outdated and does not reflect the current Alberta economy.[120] It added that it was unreasonable for ATCO Electric to attempt to make up a perceived 12 per cent compensation deficit under conditions in which many of its reported peer companies, including Canadian Oil Sands Limited, Devon Canada Corporation, and Penn West Exploration, have experienced a mix of layoffs, wage freezes and wage rollbacks. In its view, these types of responses by peer companies to current labour market conditions may result in ATCO Electric overshooting its intended wage target, instead of meeting median expectations.[121]

[113] Exhibit 20272-X0003, application, Section 31, Attachment 31.13, PDF pages 1449-1470.
[114] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 43, PDF pages 153-154.
[115] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 44, PDF page 154.
[116] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraphs 45-64, PDF pages 154-157.
[117] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 50, PDF page 157.
[118] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 51, PDF page 157.
[119] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 52, PDF page 157.
[120] Exhibit 20272-X1297, RPG argument, paragraph 112, PDF page 54.
[121] Exhibit 20272-X1297, RPG argument, paragraph 114, PDF page 55.

165. ATCO Electric also claimed that "it is attempting to deal with salary compression issues (between union and non-union employees), as well as address the expected improvement in economic conditions." It further explained that its forecast was created using compensation data from numerous government and industry sources, including other utilities, in addition to the study prepared by Mercer. It submitted that its forecast inflation rates for 2016 and 2017 reflect this information and an effort by ATCO Electric to close the compensation differential in the Mercer report while keeping its compensation for out-of-scope employees at reasonable market levels.[122]

166. In reply to ATCO Electric's argument, the RPG stated that if ATCO Electric has compensation compression problems between union and non-union workers it is in part due to ATCO Electric negotiating a collective agreement with too high an inflation rate. In its view, ratepayers should not over-compensate out-of-scope staff as well.[123] The RPG also submitted that ATCO Electric's out-of-scope inflation rates for 2016 and 2017 assume that economic conditions will improve in the later test years, but that no evidence was submitted to establish the reasonableness of this assumption.[124]

167. In reply, ATCO Electric reiterated that it had reduced its inflation forecast for 2015 for out-of-scope employees to 0.3 per cent, in light of prevailing economic conditions. The utility also pointed to the fact that its out-of-scope employees continue to lag behind the in-scope workers and are below the market median for comparable companies, as demonstrated by the Mercer report.[125] It claimed that the proposed inflation adjustment of 0.3 per cent for out-of-scope employees in 2015 is below actual inflation experienced in the period, and that this will likely result in out-of-scope employees falling further behind the market median, further aggravating the salary compression issues it faces.[126]

168. ATCO Electric stated that "[w]hile AET essentially kept its out-of-scope employees flat during 2015, it is simply not sustainable to think that compensation for this group of employees can remain at that level for the balance of the Test Years. To the contrary, in order to keep pace with in-scope employees and not allow the existing gap between AET's employees and its market competitors to widen further, it is necessary for AET to provide a reasonable inflation adjustment for out-of-scope employees in 2016 and 2017."[127]

Commission findings

169. The Mercer 2015 Total Remuneration Review provided in ATCO Electric's application is dated March 6, 2015. This report includes a table that shows a comparison of the percentage differential between ATCO Electric and a peer group of 48 companies based on base salary, target total cash compensation, target total direct compensation and target total remuneration. Its summary conclusions are shown below:[128]

[122] Exhibit 20272-X1298, ATCO Electric argument, paragraph 47, PDF page27.
[123] Exhibit 20272-X1307, RPG reply argument, paragraph 103, PDF page 32.
[124] Exhibit 20272-X1307, RPG reply argument, paragraph 104, PDF pages 32-33.
[125] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 23, PDF page 16.
[126] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 24, PDF pages 16-17.
[127] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 25, PDF page 17.
[128] Exhibit 20272-X0003, Section 31 Attachment 31.13, page 3 of 22.

Table 9. Summary of Mercer percentage differential from median compensation

Compensation element	% differential from P50
Base salary	+ 2%
Target total cash compensation	- 3%
Target total direct compensation	- 7%
Target total remuneration	- 12%

Source: Exhibit 20272-X0003, application, Section 31, Attachment 31.3, PDF page1462.

170. In IR AET-AUC-2015JUN08-022 (h)(i), the Commission asked ATCO Electric in what peer group percentile it fell for each of the four compensation elements used in the study. ATCO Electric provided the above table in response to the Commission's IR. The Commission finds that this information is of little assistance to it in assessing the reasonableness of ATCO Electric's requested out-of-scope wage inflation rates. While the provided information indicates whether ATCO Electric is above or below the median for each of the four categories, it does not, without the requested additional information regarding percentiles within the comparator group, provide any insight into the relative significance of the difference. In other words, the Commission is unable to determine how many of ATCO Electric's comparator companies are between ATCO Electric and the median value.

171. In questioning by Commission Member Lyttle, ATCO Electric acknowledged that it was targeting the 3.75 per cent out-of-scope labour inflation increase to be within 10 per cent of the peer group median from the Mercer survey.

> Q. Should we redesign this then?
>
> A. MR. DECHAMPLAIN: We believe the design is fit for purpose. In times when we need to pay the VPP in order to attract and retain the staff and they meet their performance goals, then it's reasonable compensation expense. We are just outside of the market through that Mercer's survey. It shows us 12 percent below the mid, so 12 percent below the 50th percentile, a little bit higher in base, but we are down below market to a great extent because of VPP.
>
> Our proposal is to have that 3 percent increase in our base pay that would just get us within that plus or minus 10 percent range for market. So we believe we are fairly and appropriately compensating our staff. The VPP if fully paid would still keep them within that range. So we do think it's designed for the times and affords us the flexibility to pay or not pay depending on economic conditions and the achievement of performance objectives.[129]

172. The Commission does not agree with the proposition that base salary should be used to make up for differences in components of compensation that are based on potential, and not actual, pay. As summarized in the table above, the Mercer survey shows that ATCO Electric is already two per cent above the median for base pay compared to its peer group. The Mercer study also fails to provide the Commission with a basis to determine the impact of a 3.75 per cent increase in base pay on ATCO Electric's (1) percentile ranking relative to peer companies and (2) position relative to the market median for each of the four listed categories of compensation/remuneration.

[129] Transcript, Volume 10, page 1680, line 16 to page 1681, line 9.

173. Further, as identified by the RPG, the Mercer study was a year old by the time this proceeding concluded. Since it was prepared, a number of peer companies included in the study have frozen or reduced employee wages.[130]

174. In light of the foregoing, the Commission does not find ATCO Electric's forecast of a 3.75 per cent increase in out-of-scope labour inflation for each of 2016 and 2017 to be reasonable. The most recent information provided to the Commission by ATCO Electric on actual wage inflation rates for out-of-scope labour relates to ATCO Electric's own experience in limiting inflation-based wage increases for out-of-scope labour to 0.3 per cent in 2015. ATCO Electric has not provided updated information demonstrating that companies in its peer group have experienced in 2016, or are readying themselves in 2017, for labour inflation rate increases of the magnitude it has proposed for its own out-of-scope labour in these two tests years. The Commission views ATCO Electric's most recent labour inflation increase for out-of-scope employees as the most accurate and timely information available with respect to anticipated market increases. Accordingly, the Commission approves an out-of-scope labour inflation rate of 0.3 per cent for the years 2015, 2016 and 2017.

5.2.2 Variable pay program (VPP)

175. ATCO Electric Transmission applied for VPP in the amounts identified in the table below.

Table 10. Summary of variable pay included in revenue requirement

	Test period		
	2015	**2016**	**2017**
	($ million)		
Transmission direct O&M - 566	0.5	0.7	0.8
Direct assigned capital	4.6	4.0	4.2
Non-direct assigned capital	1.4	1.4	1.5
Transmission	6.5	6.1	6.4
Isolated generation O&M - 557	0.0	0.0	0.0
Isolated generation O&M - 557	0.0	0.0	0.0
Corporate O&M - 920	0.3	0.4	0.5
Corporate	0.3	0.4	0.5
Total	**6.8**	**6.5**	**7.0**

Source: Exhibit 20272-X1101, Schedule 25-11.

176. The UCA submitted that it was unfair to have customers pay for incentive compensation in difficult economic times and generally questioned ATCO Electric's current need to pay VPP to retain and attract employees.[131]

177. The RPG noted in evidence that ATCO Electric had previously requested approval to expand its VPP to additional employees in 2012 in order to be competitive in terms of its total

[130] Exhibit 20272-X1297, RPG argument, paragraph 114, PDF page 55.
[131] Exhibit 20272-X0777, UCA evidence, A.31, PDF page 21.

cash compensation, but that a substantial portion of the approved amounts was not actually paid out in either 2013 or 2014. The RPG pointed out that those unpaid VPP dollars ultimately benefited shareholders because the deferral account for VPP was eliminated in Decision 2013-358.[132]

178. In its rebuttal evidence, ATCO Electric stated that it was revising its VPP forecast for 2015 to zero, and that it would update the impact of this decision in its compliance filing. ATCO Electric did not alter its existing 2016-2017 VPP forecast, explaining that this would ensure that its employees were appropriately compensated.[133]

179. In its argument, the UCA noted that ATCO Electric did not pay VPP in 2015 due to prevailing economic conditions, while ATCO Ltd., its indirect parent, declared a 2016 Q1 dividend that represented a 15 per cent increase over the quarterly dividends paid in 2015, thereby effectively immunizing its shareholders from the impact of the recent economic downturn.[134] Noting the current economic conditions in Alberta, the UCA recommended that all VPP amounts be disallowed for 2015, 2016 and 2017. In its view, the rationale offered by ATCO Electric underpinning the need for VPP in 2016 and 2017 is speculative, unsupported, or both.[135]

180. The UCA argued that if the Commission were to approve VPP for the 2016 and 2017 test years, the approved amounts should reflect the historical underpayment of VPP in 2013-2014.[136]

181. The RPG recommended that:[137]

- The Commission direct ATCO Electric to reduce its forecast for O&M and capital VPP to zero for both 2016 and 2017.
- For direct assigned and non-direct assigned capital staff, the inclusion of actual VPP be suspended for revenue requirement purposes until such time as the utility submits a revised and reformed proposal for the payment of a VPP that demonstrates its necessity and benefits to customers.
- The Commission direct ATCO Electric to file a revised proposal for the payment of VPP that properly aligns the interests of customers, employees and the utility, as part of its next GTA.

182. Both the UCA and RPG opposed the re-establishment of a deferral account for VPP.

183. ATCO Electric argued that VPP is a critical component of its overall compensation and that it has established a track record of paying VPP to an increasing segment of its employee population. It submitted that making partial VPP payments in 2014 and not paying VPP in 2015 does not change the purpose or need for VPP going forward.[138] ATCO Electric maintained that its previous decisions whether to pay VPP were based on economic conditions and the underlying need to attract and retain its required workforce.[139]

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132 Exhibit 20272-X0789, RPG evidence, paragraphs 191-194, PDF pages 76-78.
133 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page171.
134 Exhibit 20272-X1296, UCA argument, paragraph 22, PDF pages 13-14.
135 Exhibit 20272-X1296, UCA argument, paragraphs 23-25, PDF pages 14-15.
136 Exhibit 20272-X1296, UCA argument, paragraph 30, PDF page 16.
137 Exhibit 20272-X1297, RPG argument, paragraphs 266 and 268, PDF pages 95-06.
138 Exhibit 20272-X1298, ATCO Electric argument, paragraph 373, PDF page 144.
139 Exhibit 20272-X1298, ATCO Electric argument, paragraph 377, PDF pages 145-146.

Commission findings

184. In response to a Commission information request, ATCO Electric confirmed that there have been no changes to VPP from previous applications.[140]

185. At the oral hearing, ATCO Electric confirmed that it would not be providing VPP payments to its employees for 2015.[141] The Commission, therefore, directs that ATCO Electric adjust its forecast VPP amounts for this test year to zero, based on actuals.

186. The Commission explained its rationale for instituting, and later removing, deferral account treatment for VPP expenditures in ATCO Electric's 2013-2014 GTA:[142]

> 72. One of the reasons why the VPP deferral account was initially established was because the regulator was concerned that as it was a new program, that in the absence of a deferral account, the utility might be incented to not pay to employees all of the VPP amounts included in the approved revenue requirement and instead, keep some of these revenues. Such protection is no longer required because ATCO Electric has established a history of paying the VPP amounts. In addition, there will be pressure from employees for ATCO Electric to continue to pay these VPP amounts, and the Commission and interveners will undoubtedly compare the actual amount of VPP payments made by ATCO Electric in 2013 and 2014 to the forecast approved amounts, as part of ATCO Electric's next transmission GTA.
>
> 73. Unlike a lot of other areas for which ATCO Electric requested deferral treatment, the decision whether or not to pay out the VPP is entirely under the control of ATCO Electric. For all of these reasons, deferral treatment for the O&M component of the VPP shall be discontinued, and deferral treatment will not be granted for the non-direct assigned capital projects component either.

187. The above excerpt from Decision 2013-358 makes it very clear that among the Commission's principal concerns with respect to approving the establishment of a ratepayer funded VPP, absent a deferral account, was that the utility might be perversely incented to appropriate, for the benefit of shareholders, funds that were collected from ratepayers to support the utility's recruitment and retention efforts. Nevertheless, for the reasons provided above, after several years of experience with ATCO Electric's VPP, the Commission determined that the risk of this occurring had diminished to such an extent that a deferral account for VPP was no longer required. This is the backdrop to the Commission concerns with respect to ATCO Electric's reasons for not fully paying out VPP amounts in 2013 and 2014, and withholding in their entirety all VPP amounts initially forecast to be paid in 2015. These concerns are compounded by the fact, as the UCA observed, that the same economic conditions that resulted in ATCO Electric withholding VPP payments from eligible employees in 2015 provided no similar barrier to its parent corporation's decision to increase dividend payments to shareholders in the very same year.

188. ATCO Electric explained the manner in which the administration of its VPP may be subject to its parent's influence, in the following exchanges with the CCA's counsel, Mr. Wachowich, and later, Commission Member Lyttle:

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[140] Exhibit 20272-X1068, response to IR AET-AUC-2015JUN08-016(g)iii revised.
[141] Transcript, Volume 4, page 661, line 4 to page 662, line 16.
[142] Decision 2013-358, paragraphs 72-73.

> Q. Okay. Sir, was something like human resources issues, such as bonuses, are those decided outside of the company ATCO Electric Limited for ATCO Electric Limited employees?
>
> A. MR. DECHAMPLAIN: I don't think there's been any change in our variable pay program since it was first proposed in -- I don't know if it was the 2005-2016 [sic] GTA or maybe the '7-'8 GTA where our chief executive officer -- sorry, any payments under the VPP program are subject to the CEO's approval, the ATCO Ltd.'s CEO.
>
> Q. Okay. So ATCO Electric -- ATCO Ltd.'s CEO has a hand in certain human resources aspects of the company dealing, for example, with variable pay, as you've just described.
>
> A. MR. DECHAMPLAIN: She held veto power, yes, sir[143]

And

> Q. Should we redesign this then?
>
> A. MR. DECHAMPLAIN: We believe the design is fit for purpose. In times when we need to pay the VPP in order to attract and retain the staff and they meet their performance goals, then it's reasonable compensation expense. We are just outside of the market through that Mercer's survey. It shows us 12 percent below the mid, so 12 percent below the 50th percentile, a little bit higher in base, but we are down below market to a great extent because of VPP.
>
> Our proposal is to have that 3 percent increase in our base pay that would just get us within that plus or minus 10 percent range for market. So we believe we are fairly and appropriately compensating our staff. The VPP if fully paid would still keep them within that range. So we do think it's designed for the times and affords us the flexibility to pay or not pay depending on economic conditions and the achievement of performance objectives.[144] [emphasis added]

189. It remains unclear to the Commission, based on the above exchange, whether ATCO Electric will pay VPP amounts in 2016 and 2017. Mr. DeChamplain confirmed that all decisions with respect to VPP payment amounts at ATCO Electric "are subject to [the ATCO Ltd.] CEO's approval" based on economic conditions, apparently even if all of the utility's internal performance criteria are otherwise met. This suggests to the Commission that, were it to approve ATCO Electric's forecast expenditures for VPP in 2016 and 2017, there is no assurance that VPP payments will actually be made even if employees achieve or exceed all their performance targets. The result is that, unlike other forecast expenditures which may or may not be incurred because of external factors outside of ATCO Electric's control, VPP amounts, which are fully within ATCO Electric's control to pay, can be withheld from employees to the benefit of shareholders (and the cost of ratepayers) based on directions received from the CEO of ATCO Electric's ultimate parent company.

190. The Commission considers that VPPs are an accepted and valid component of employee compensation. VPPs enable firms, including utilities, to attract and retain qualified and motivated workers. When they are well designed and managed, VPPs can also incent employees to identify and exploit opportunities to realize operational efficiencies. However, the

[143] Transcript, Volume 2, page 206, lines 8-22.
[144] Transcript, Volume 10, page 1680, line 16 to page 1681, line 164.

Commission considers that many of these benefits are diminished, if not lost entirely, in circumstances where employees perceive the administration of a VPP to be unpredictable or inequitable.

191. ATCO Electric has not exceeded an actual payout of 83 per cent of its forecast VPP amount since the deferral account treatment was removed.[145] Its VPP forecasts for 2016 and 2017 are approved at 80 per cent of the eligible employee payout amounts.

192. The Commission directs ATCO Electric to set up a VPP reserve account in its no cost capital schedules in Section 29 of ATCO Electric's revenue requirement schedules. Regarding the mechanics of the reserve account, ATCO Electric will not be eligible to recover costs in excess of the approved VPP forecast amounts for a given year, and will not be permitted to carry over unused VPP funds for use in future years of the current application. Approved, but unused, VPP amounts in any given GTA test period will be added to the VPP reserve account for the next GTA test period. In the Commission's view, this approach will address the legitimate need to maintain funding for ATCO Electric's VPP in support of its recruitment, retention and operational performance goals, while insuring that any incentive to withhold VPP amounts otherwise payable to eligible employees based on their performance, in order to increase the utility's retained earnings, is removed.

5.3 Other escalators

5.3.1 Other inflation

193. ATCO Electric forecasted "other inflation" to be 2.0 per cent for the years 2015, 2016 and 2017. These rates were determined using an average of Alberta CPI forecast rates from a number of government and financial institutions.[146]

194. In its evidence, the RPG provided a reference to an Alberta Government Treasury Board and Finance economic outlook dated October 27, 2015. This report forecasted a CPI of 0.9 per cent for 2015, 1.7 per cent for 2016 and 1.9 per cent for 2017.[147]

195. In argument, RPG took issue with ATCO Electric's failure to update its "other inflation" rate since first filing its application, and pointed out that the "other inflation" input is used as part of the calculation in the contractor and capital inflation. It stated that even if the impact of "other inflation" in dollars is less significant than other cost items, it should be as accurate as possible to maintain the accuracy of the other inflation categories it affects.[148] The RPG requested that the Commission accept its recommendations for other inflation rates of 0.9 per cent in 2015, 1.6 per cent in 2016 and 1.9 per cent in 2017.[149]

196. ATCO Electric, in argument, reiterated the sources of its forecasted "other inflation" increase of 2.0 per cent for each of the test years, and noted that its forecasted amounts for 2016 and 2017 are close to the updated Alberta Treasury and Finance Board forecasts for the same time period.[150]

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145 Exhibit 20272-X0623, response to IR AET-AUC-2015OCT16-001(c).
146 Exhibit 20272-X1100, revised application, page 1-27, PDF page 27.
147 Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 63, PDF page 161.
148 Exhibit 20272-X1297, RPG argument, paragraphs 116-117, PDF page 56.
149 Exhibit 20272-X1297, RPG argument, paragraph 119, PDF pages 56-57.
150 Exhibit 20272-X1298, ATCO Electric argument, paragraph 54, PDF page 29.

Commission findings

197. ATCO Electric addressed the impact of inflation on operating costs in Section 01 Attachment 1.1 – Transmission Inflation – Revised February 23, 2016.[151] The dollar impact of a two per cent "other inflation" rate to O&M, as disclosed on line 37 of that schedule, is $0.7 million, $0.5 million and $0.5 million for the years 2015, 2016 and 2017, respectively. "Other inflation" also affects the contractor and capital inflation rates. Although the dollar impacts of "other inflation" on contractor inflation dollars and capital inflation dollars were not quantified in this schedule, the Commission considers it likely that the impacts on these amounts will be material.

198. At the oral hearing, the RPG provided an update to the Alberta CPI sourced from the Alberta Government's 2015-16 Third Quarter Update – Economic Outlook. This update shows the Alberta CPI for 2015 increasing to 1.1 per cent from 0.9 per cent, and decreasing from 1.7 per cent to 1.6 per cent in 2016.

199. In the hearing, ATCO Electric witness Mr. Jansen, clarified how the "other inflation" rate was incorporated into the utility's forecast for contractor and capital inflation rates.

> The calculation shows a weighted inflator rate of 2.7 percent in 2016 calculated as the internal labour inflation rate and a 3.75 percent times a 36 percent weighting and a CPI rate of 2.1 percent times 64 percent weighting. The same was done for 2017 but with a CPI rate of 1.9 percent.[152]

200. The Commission considers that this statement confirms that ATCO Electric did not use its own forecast "other inflation" rate of 2.0 per cent as an input into its calculation of forecast contractor and capital inflation rates, but rather used 2.1 per cent.

201. In the Commission's view, the Alberta CPI update provided by the RPG at the oral hearing represents the most up to date information available for use in determining past and forecast "other inflation" rates for the test years. The Commission accepts the RPG's recommended "other inflation" rates of 1.6 per cent and 1.9 per cent for 2016 and 2017, respectively. Based on the Alberta Government's 2015-16 Third Quarter Update, the Commission finds that it is reasonable to update the 2015 rate to 1.1 per cent, as well. ATCO Electric is directed to update its other inflation rates to 1.1 per cent for 2015, 1.6 per cent for 2016 and 1.9 per cent for 2017.

202. ATCO Electric is to revise its "other inflation" rates as directed here only after adjustments have been made pursuant to all other directions in this decision.

5.3.2 Contractor and capital inflation

203. In its O&U filing, ATCO Electric stated that it had forecasted contractor costs using 2015 dollars and, consequently, a contractor inflation factor was not applied to the 2015 amounts. It added that the changing economic landscape made it difficult to forecast a reliable inflation trend for contractors, so it instead adopted a macro-level approach to forecasting its contractor inflation rates. Consequently, the 2016 and 2017 forecasted contractor inflation rates used by ATCO Electric were a composite of its "other" inflation rate based on Alberta CPI, and its own

[151] Exhibit 20272-X1100, revised application, Attachment 1.1, Transmission Inflation.
[152] Transcript, Volume 1, page 22, lines 13-18.

labour inflation rate. The contractor inflation rates were finally revised to 2.7 per cent for 2016 and 2.5 per cent for 2017.[153]

204. The RPG was concerned that ATCO Electric's forecasts for "other" inflation and its own labour inflation were too high. It also questioned the use of a weighting approach in the determination of the composite contractor rate.[154]

205. The RPG submitted that extensive layoffs in the oil and gas sector had resulted in Calgary-based companies seeing reductions in their contractor rates and questioned why ATCO Electric should not expect similar impacts on its own rates.[155] The RPG also referenced a Stats Canada report showing decreases in the prices of raw materials, which, in its view, should also result in lower material costs for ATCO Electric.[156]

206. The RPG recommended inflation rates of -10.0 per cent in 2015 (for non-direct assigned contractor capital), zero per cent in 2016, and zero per cent in 2017. The RPG also recommended that the actual inflation be used for ATCO Electric's 2015 direct assigned contractor capital. It also argued that ATCO Electric is not bound by AESO Rule 9.1.5 for non-direct assigned capital projects and can negotiate with contractors, and should seek reductions in the same range as those being obtained by other large Alberta companies.[157]

207. ATCO Electric stated in argument that it has observed an overall increase in contractor and capital inflation in 2015 of well above CPI, mainly due to the impacts of the foreign exchange rate on U.S. purchases and the loss of volume discounts. It claimed that those impacts were partially offset by lower commodity prices for materials. ATCO Electric expected this trend to continue into 2016.[158]

Commission findings

208. ATCO Electric stated that it forecasted contractor costs for 2015 in 2015 dollars. As a result, contractor inflation is already incorporated into the 2015 forecast amount. On this basis, the Commission rejects the RPG's recommendation of a -10.0 per cent rate for capital inflation for 2015. The Commission approves ATCO Electric's contractor and capital inflation rate of zero per cent for 2015.

209. The Commission agrees that it is reasonable to expect that extensive job losses and project cancellations in the oil and gas sector should lead to contract bids becoming more competitive. It also finds that the pricing of materials can reasonably be expected to reflect decreases in commodity prices. However, the Commission also accepts that impacts of other factors including changes in exchange rates and the loss of volume discounts may offset any savings eventually realized by ATCO Electric.

210. The Commission approves ATCO Electric's use of a weighted average approach to calculate its contractor and capital inflation rates. The Commission directed ATCO Electric to update its "other" and labour inflation rates in sections 5.2.1 and 5.3.1 above. The Commission finds that the approved out-of-scope labour inflation rate best reflects the current contractor

[153] Exhibit 20272-X0604, ATCO Electric O&U filing, paragraph 7, pages 6-7 of 42.
[154] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraphs 65-66, PDF page 162.
[155] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraphs 67-71, PDF pages 162-163.
[156] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 72, PDF page 163.
[157] Exhibit 20272-X0789, RPG evidence, Appendix A, paragraph 76, PDF page 164.
[158] Exhibit 20272-X1298, ATCO Electric argument, paragraph 52, PDF pages 28-29.

labour market. Based on the out-of-scope labour inflation and "other inflation" rates the Commission has approved in previous sections of this decision, ATCO Electric is directed to use a contractor and capital inflation rate of 1.1 per cent[159] in 2016 and 1.3 per cent[160] in 2017.

211. As with the other inflation adjustments identified above, ATCO Electric is to apply changes to its contractor and capital inflation rate after adjustments from all other directions contained in this decision have been made.

5.4 Placeholders and deferral accounts

212. In the updated application, ATCO Electric requested the approval of various placeholders and provided an updated placeholder schedule[161] on March 3, 2016. The Commission notes that when the application was prepared, along with the numerous updates, there were certain items included that may be affected by other applications that were either underway or scheduled to be submitted to the Commission. ATCO Electric requested approval to treat these particular items as placeholders pending the outcome of these other applications. Once the other applications are finalized, ATCO Electric will revise the placeholder amounts as determined in those proceedings and calculate the resulting impact on the revenue requirements for the 2015-2017 test period. The resulting impacts on the revenue requirements would then be included in the annual filing for adjustment balances that ATCO Electric submits to the Commission for approval. Approval was requested for the following placeholders summarized on the updated placeholder schedule:

- common group costs
- corporate license fees
- IT common matters costs for price only, not volumes
- Transmission line insurance costs
- return on equity and common equity ratios
- defined benefit plan pension costs

213. The proposed placeholder for transmission line insurance costs will be addressed in a separate section of this decision as part of corporate administrative and general costs.

5.4.1 Common group costs placeholder

214. In a December 4, 2015 Commission ruling on a UCA motion related to ATCO Electric's November 30, 2015 announcement of organizational changes resulting in workforce reductions, the Commission determined that additional information was required beyond that proposed to be provided by the company.[162]

215. In ATCO Electric's response to the directions in the Commission's ruling, it included the following information on impacts resulting from the common group:

> In response to the impacts on its business resulting from the current economic times, AET has recently undergone certain organizational changes. This has resulted in workforce reductions and included the increased utilization of common groups, where these measures can be effectively implemented.

[159] 2016 contractor and capital inflation = (0.64 *1.6 "other" inflation) + (0.36*0.3 out-of-scope labour inflation).
[160] 2017 contractor and capital inflation = (0.64 *1.9 "other" inflation) + (0.36*0.3 out-of-scope labour inflation).
[161] Exhibit 20272-X1136, Attachment 2 – revised placeholder schedule.
[162] Exhibit 20272-X0699, Commission ruling on UCA motion, paragraphs 1-23, PDF pages 1-6.

….

> The allocation and cost information for common groups is currently under review and, as such, is not yet available. A preliminary review completed by ATCO Electric has indicated that the implementation of common groups mainly impacts the capital costs incurred by ATCO Electric and is not expected to have a material impact on its operating costs. ATCO Electric proposes placeholder treatment for 2016 and 2017 associated with the savings to O&M related costs arising from workforce reductions and the implementation of common groups. Specifically, ATCO Electric is requesting placeholder treatment for 2016 and 2017 forecast savings. These placeholders will be adjusted in a future proceeding which will allow the AUC to test the costs transferred out of ATCO Electric into the common group costs and the common group cost allocations to ATCO Electric. ATCO Electric proposes to submit this filing by June 30, 2016.[163]

216. In ATCO Electric's updated placeholder schedule[164] filed on March 3, 2016, it included proposed placeholder amounts for common group costs of $12.3 million and $13.2 million for 2016 and 2017, respectively.

217. On June 8, 2016, ATCO Electric submitted its Common Group application which was assigned Proceeding 21701, and included proposed common group costs of $9.8 million and $10.0 million for 2016 and 2017, respectively.

218. The Commission notes that none of the interested parties proposed adjustments to the common group placeholders. The Commission has reviewed the information provided in the current proceeding as well as the updated placeholder amounts filed in Proceeding 20701 in the Common Group application identified above. Given the significant organizational changes identified by ATCO Electric, the recent timing of these changes and the fact that the Commission and interested parties will be able to examine additional information as part of the separate proceeding before determining the final common group cost amounts, the Commission will grant ATCO Electric's request for placeholder treatment of common group costs for 2016 and for 2017. As ATCO Electric had proposed placeholder amounts in the current proceeding after stating that the supporting information would be available in the subsequent proceeding, and now that the requested amounts have been updated in that proceeding, the Commission approves the updated placeholder amounts of $9.8 million and $10.0 million for 2016 and 2017, respectively.

5.4.2 Licence fees

219. In ATCO Electric's updated placeholder schedule[165] filed on March 3, 2016, it included proposed placeholder amounts for corporate licence fees of $2.7 million, $3.1 million and $4.7 million for 2015, 2016 and 2017, respectively.

220. In a letter dated October 28, 2015, the Commission directed ATCO Electric and ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., to file a joint licence fee application with the Commission which included all licence fee related evidence, rebuttal evidence and responses to IRs filed in proceedings 3577 and 20272.[166] The application was assigned Proceeding 21029.

[163] Exhibit 20272-X0700, ATCO Electric additional information submission, PDF pages 1-2.
[164] Exhibit 20272-X1136, Attachment 2 – revised placeholder schedule.
[165] Exhibit 20272-X1136, Attachment 2 – revised placeholder schedule.
[166] Exhibit 20272-X0617, Commission process letter to address license fees, paragraphs 1-9, PDF pages 1-2.

221. Decision 21029-D01-2016[167] was issued on June 30, 2016, and it included the following information on the proposed corporate licence fees:

> 20. The ATCO Utilities requested that the Commission approve certain amounts attributable to licence fee payments in their respective revenue requirements. These licence fees, which are payable to ATCO Ltd., are intended to compensate that company for its subsidiaries' use of intangibles and associated benefits that they receive as a result of their relationship with their indirect parent. The intangibles covered by the licensing fees include purchasing power benefits and economies of scope and scale, as well as the benefit of the ATCO Ltd. name, trademarks, intellectual property and know-how.[168]

222. Decision 21029-D01-2016 make the following determinations:

> 122. Overall, the Commission is not persuaded that the licence fees payable by ATCO Electric and ATCO Pipelines constitute costs reasonably incurred in connection with the provision of utility services. The question of whether ATCO Ltd. is obliged to charge the licence fee to comply with Canadian tax law is not determinative of whether the amounts being paid by ATCO Electric and ATCO Pipelines should be included in their respective revenue requirements. The Commission is also concerned by the apparent divergence of opinion between Gowlings and the utilities with respect to the kinds of benefits realized by the utilities' association with ATCO Ltd. and how they are accounted for in the fee being charged. Finally, there appears to have been no effort on the part of either ATCO Electric or ATCO Pipelines to critically assess or otherwise understand their parent's valuation of the licence fee with a view to ensuring fair value was being obtained for the amounts paid. The Commission finds this behaviour to be inconsistent with what might reasonably be expected of standalone entities. The Commission finds that licence fee payments by the regulated utilities, and indirectly by customers, should not be included in revenue requirement.
>
> 123. ATCO Electric and ATCO Pipelines' licence fees application is therefore denied. ATCO Electric is directed to reflect the findings of this decision in the compliance filing to its 2015-2017 general tariff application, Proceeding 20272. ATCO Pipelines is directed to remove the licence fees placeholders from its next general rate application.[169]

223. Based on these determinations in Decision 21029-D01-2016, issued on June 30, 2016, the Commission denies the proposed corporate licence fee placeholders of $2.7 million, $3.1 million and $4.7 million for 2015, 2016 and 2017, respectively. The Commission directs ATCO Electric, in the compliance filing, to remove these placeholder amounts from the revenue requirement in each of the test years.

5.4.3 ATCO Utilities IT common matters

224. ATCO Electric's updated placeholder schedule, filed on March 3, 2016, did not include any proposed placeholder amounts for IT common matters, whether in dollars or units for any of the test years.

225. On June 4, 2015, the Commission issued Bulletin 2015-11 to initiate a common matters proceeding (Proceeding 20514) to examine IT costs related to master service agreements (MSAs)

[167] Decision 21029-D01-2016: ATCO Electric Transmission and ATCO Pipelines, Application for ATCO Electric Transmission 2015-2017 and ATCO Pipelines 2015-2016 Licence Fees, Proceeding 21029, June 30, 2016.
[168] Decision 21029-D01-2016, paragraph 20.
[169] Decision 21029-D01-2016, paragraphs 122-123.

that had been entered into between ATCO Electric and ATCO Pipelines, respectively, with Wipro Solutions Canada Limited for the provision of IT services commencing January 1, 2015.[170]

226. On November 19, 2015, the Commission suspended its current process schedule as requested by ATCO Utilities to allow time to complete a benchmark report of the IT MSAs.[171] In accordance with a Commission direction, ATCO Utilities updated the Commission on the status of the report, and indicated that it would be completed by the end of June 2016 and filed with the Commission shortly thereafter.[172]

227. The Commission notes that matters related to pricing of IT services will be determined in the IT common matters proceeding, but the testing and determination of IT volumes will occur in the current proceeding. For that reason, the Commission finds that no placeholder is required for IT volumes. Since IT prices are being determined in Proceeding 20514, a placeholder for IT cost amounts would not be unreasonable. The Commission notes, however, based on the proceeding record, that ATCO Electric has not proposed such a placeholder.

228. The Commission directs ATCO Electric, in the compliance filing, to confirm whether it has proposed an IT cost placeholder in relation to the IT common matters proceeding which is examining IT pricing. ATCO Electric is directed to prepare and file a schedule, in the compliance filing, summarizing the IT costs included in the application by test year, within each cost area, being O&M, ES&G, and capital, displaying the accounts used for these charges in each cost area.

5.4.4 Return on equity and common equity ratios

229. In ATCO Electric's updated placeholder schedule filed on March 3, 2016, it included proposed placeholders of 8.30 per cent for return on equity and 36.0 per cent for the common equity ratio for each of 2015, 2016 and 2017.

230. Decision 2191-D01-2015[173] determined the final approved return on equity and deemed equity ratio for 2013-2015 of 8.3 per cent and 36 per cent respectively. The return on equity and deemed equity ratio was also "approved on an interim basis for 2016, and for each subsequent year thereafter, unless otherwise directed by the Commission."[174]

231. The Commission notes that ATCO Electric has proposed placeholders for return on equity and the common equity ratio for each of the test years from 2015 to 2017. Decision 2191-D01-2015, however, determined the final return on equity and common equity ratio for 2015. Therefore, the Commission approves placeholder treatment for return on equity of 8.30 per cent, and the common equity ratio of 36 per cent for 2016 and 2017. The Commission denies use of a placeholder for 2015 as proposed by ATCO Electric as these amounts were determined on a final basis for 2015.

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[170] Bulletin 2015-11, Initiating the ATCO Utilities information technology (IT) common matters proceeding to examine IT costs related to the master services agreements (MSAs) between the ATCO Utilities and Wipro Solutions Canada Limited (Wipro).
[171] Exhibit 20514-X0115, Commission letter to suspend proceeding, PDF pages 1-3.
[172] Exhibit 20514-X0116, ATCO Utilities report status letter.
[173] Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.
[174] Decision 2191-D01-2015, paragraph 506.

5.4.5 Defined benefit plan pension costs

232. In ATCO Electric's updated placeholder schedule filed on March 3, 2016, it included a proposed placeholder amount, for the 2017 test year only, of $3.4 million for defined benefit plan pension costs. The schedule also included a defined benefit special payments deferral account with zero dollars included for each test year.

233. In ATCO Electric's updated application, it proposed the 2017 defined benefit plan pension cost placeholder as follows:

> 25. The 2014 Pension Application (filed September 10, 2014) includes the most recent actuarial valuation 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. This Application includes forecast defined benefit plan funding as recommended by this valuation. Given no actuarial valuation has occurred yet relating to the 2017 period, AET has included the same funding amounts as identified for the 2014 to 2016 period in the 2017 Test Period forecast. AET requests that the 2017 defined benefit pension costs forecast in this application be treated as a placeholder.[175]

234. On July 20, 2016, ATCO Utilities filed a pension application, which was assigned Proceeding 21831. In the application, ATCO Utilities explained that the 2014 pension application mentioned in the above excerpt from ATCO Electric's application in the current proceeding had been withdrawn and was replaced by the more recent pension application which incorporated the results of two different Mercer pension evaluations, one dated December 31, 2013 and the other dated December 31, 2015.

235. In the application for Proceeding 21831, ATCO Utilities clarified the intended uses of the two Mercer pension evaluations as follows:

> The December 31, 2013 Mercer report will be the basis for the requested 2014/2015 pension cost recovery and the December 31, 2015 Mercer report will be for 2016 onwards until a new pension valuation is required.[176]

236. In Decision 20273-D01-2015,[177] the Commission approved the 2013 ATCO Utilities pension costs as final and updated the placeholders for 2014.[178] ATCO Electric has only proposed a placeholder for defined benefit pension costs in 2017. The Commission finds that pension costs for 2014 through 2016 onwards will be determined in proceeding 21831and its related compliance filing, for a test year period overlapping the three test years in the current application.

237. The Commission finds that the test years in the current application shall have placeholder treatment for defined benefit pension costs and that these costs for 2015, 2016 and 2017 will be determined in Proceeding 21831. The Commission therefore directs ATCO Electric to update its revised placeholder schedule (Exhibit 20272-X1136, Attachment 2) and file the updated schedule in the compliance filing to this decision.

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175 Exhibit 20272-X1100, application, paragraph 25, PDF page 15.
176 Exhibit 21831-X0003, application, paragraph 6, PDF page 4.
177 Decision 20273-D01-2015: The ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), Compliance Filing to Decision 2954-D01-2015 2013 Pension Application, Proceeding 20273, September 23, 2015.
178 Decision 20273-D01-2015, paragraph 39.

6 Fuel costs

238. In its application, ATCO Electric noted that it owns and operates nine generation plants serving isolated communities. It stated that diesel fuel powers seven of those plants, while the two remaining plants serving Jasper are powered by natural gas and diesel (Jasper Palisades) and hydro (Astoria Hydro). ATCO Electric owns 71 isolated generating plants, in addition to isolated community plants, most of which are used as station service back-up and telecommunication power supply back-up and are powered by propane.[179]

239. ATCO Electric submitted that a significant level of uncertainty attends the forecasting of fuel volumes due to possible changes in consumption patterns, individual large customer expansion plans, overall community economic growth, temperature oscillations and plant/engine efficiencies.[180]

240. ATCO Electric proposed a deferral account for the fuel price and volume variance for the following reasons:[181]

> 1. The fuel cost volatility can be very high, as shown in Table 1. The impact of this volatility is very significant.
> 2. AET has limited ability to control either the price of fuel or the volume of fuel required as a result of load variations.
> 3. There is no offsetting revenue associated with fuel price or volume changes.

241. The RPG stated that it had no specific recommendations with respect to ATCO Electric's estimated costs or its request for the application of deferral treatment to fuel costs. The RPG noted that in ATCO Electric's last test period, the fuel cost was one of the few items that the utility had under-forecast and that it was now seeking to have a deferral account approved to avoid future losses. The RPG agreed that neither the utility nor customers should bear the forecast risk of these costs as they are outside of the control of the utility, but the same principles need to be applied consistently to ensure ATCO Electric does not improperly over-earn on its forecast costs elsewhere.[182]

242. In argument, ATCO Electric submitted that the updated forecast should be approved, as filed. In addition, the requested deferral account should be approved as it meets the AUC's criteria.[183]

Commission findings

243. In its decision for Proceeding 1989, the Commission dealt with the continued use of a deferral account for fuel.[184] The Commission determined that the forecast fuel costs for 2013 represented approximately 1.3 per cent of the total forecast revenue requirement and that in 2014 the corresponding figure was approximately 1.1 per cent. The Commission considered that these percentages were not significant and also made the following comments:

[179] Exhibit 20272-X0002, application, Section 4, paragraph 77, PDF page 326.
[180] Exhibit 20272-X0002, application, Section 4, paragraph 87, PDF page 330.
[181] Exhibit 20272-X0002, application, Section 4, paragraph 98, PDF page 334.
[182] Exhibit 20272-X1297, RPG argument, paragraphs 272-273, PDF page 96.
[183] Exhibit 20272-X1298, ATCO Electric argument, paragraph 60, PDF pages 32-33.
[184] Decision 2013-358, pages 10-11.

> 39. The Commission also considers that there is no incentive for ATCO Electric to manage the level of these costs if they are afforded deferral treatment. The fuel efficiency of the isolated generating units may be improved if ATCO Electric can benefit from efficiencies but with a deferral account there is no incentive to seek out any efficiencies.
>
> 40. The Commission agrees that natural gas and diesel prices fluctuate and are not under the control of ATCO Electric, however the Commission also recognizes that there are a number of other cost items included in this application over which ATCO has no control, such as debenture rates, for which ATCO Electric is willing to accept the forecast risk.
>
> ……..
>
> 43. ….The Commission considers that the forecast fuel amounts approved in Section 6 of this decision allows ATCO Electric some room for forecast error and that the amount of the error would not be material. Based on the Commission's considerations and analysis of fuel costs, the Commission finds that a deferral account is not warranted for fuel costs and consequently rejects ATCO Electric's request for a deferral account for isolated generation fuel costs.[185]

244. The Commission is not persuaded of the merits of re-establishing a deferral account for fuel costs. The Commission finds that forecast fuel costs still do not represent a significant proportion of ATCO Electric's overall revenue requirement and that, consequently, any error in the forecast amounts can reasonably be expected to be immaterial. In addition, as the Commission stated in Decision 2013-358, the use of deferral accounts eliminates incentives to improve efficiency. Therefore, the Commission does not approve the creation of a deferral account for fuel costs for the test years.

7 Operating costs

7.1 Forecasting assuming a zero-base for O&M

245. In Decision 2013-358, the Commission set out its views on forecasting assuming a zero-base as follows:

> 163. … The Commission considers that, regardless of the organizational structure, ATCO Electric would be best to develop its forecasts from an assumed zero-base, which seeks to reassess the resources and costs required to fulfill its statutory duties on an annual basis, without assuming that costs are simply incremental to the actual or forecast costs of the preceding year.[186]

246. ATCO Electric stated that it employed an activity-based forecasting approach that includes considering the activities to be performed for each test year, and then evaluating if they are indeed required to provide safe and reliable service. It then develops its resourcing plan to support the activities and is thereby able to build a forecast of reasonable operation and maintenance costs from the bottom up.[187]

[185] Decision 2013-358, paragraphs 39-40 and 43.
[186] Decision 2013-358, paragraph 163.
[187] Exhibit 20272-X1298, paragraph 61.

Commission findings

247. The Commission is satisfied with the explanation from ATCO Electric regarding its activity-based approach. Given ATCO Electric's stated approach to building its O&M forecast, the Commission is satisfied that ATCO Electric has not developed its O&M forecast on an incremental basis from the preceding year's forecast.

7.2 Vegetation management

248. ATCO Electric forecasted that the cost to perform the O&M portion of its vegetation management (VM) program for 2015, 2016 and 2017 would be $9.3 million, $11.0 million and $10.5 million, respectively.[188]

249. ATCO Electric provided a table summarizing the projected treatment volumes. The treatment volumes were disaggregated into the treatment methods that ATCO Electric planned to use:[189]

Table 11. Vegetation management O&M volumes

	2013 actual	2014 actual	2015 test period	2016 test period	2017 test period
	(000's/m^2)				
Herbicide	3,868	2,321	11,380	8,353	12,718
Mulching	4,292	1,490	8,105	9,308	7,555
Slashing	465	309	301	894	232
Trimming	44	7	37	25	29

Source: Exhibit 20272-X1100, revised application, paragraph 227, Table 5.17, PDF page 106.

250. The RPG, in argument, submitted that the forecast increases in vegetation management costs in the test period are due to significant increases in the ratio of area subject to vegetation management treatment relative to total area under vegetation management during the 2015 to 2017 period compared with the same ratio for the historical period, as shown in Table 12:[190]

[188] Exhibit 20272-X1100, revised application, paragraph 200, PDF page 95.
[189] Exhibit 20272-X1100, revised application, paragraph 227, PDF page 106.
[190] Exhibit 20272-X1297, RPG argument, paragraph 318, PDF pages 106-107.

Table 12. RPG historical comparison of vegetation management costs and area treated

	Area under VM ('000s m^2)	Area treated ('000s m^2)	Ratio: area treated to area under VM	VM total costs ($ million):
2008	195,796	5233	2.7%	3.5
2009	199,059	4032	2.0%	3.5
2010	206,585	7960	3.9%	4.3
2011	212,944	8234	3.9%	4.9
2012	217,124	8139	3.7%	5.0
2013	230,363	8668	3.8%	5.6
2014	230,866	4127	1.8%	3.8
2015	231,093	19823	8.6%	9.3
2016	267,952	18580	6.9%	11.0
2017	271,822	20534	7.6%	10.5
Average - 2008-2014			3.1%	4.4
Average - 2012-2014			3.1%	4.8
Average - 2015-2017			7.7%	10.3

Source: AET-CCA-2015DEC30-003(a) Attachment 1.

251. The RPG submitted in its argument that the average ratio of area treated to the area under vegetation management (VM) during 2010 to 2013 would be a good benchmark against which to compare the submitted ratio of area treated to area under VM in the test period. The average ratio of area treated to area under VM during 2010 to 2013 period was 3.8 per cent. In the RPG's view, ATCO Electric did not provide a logical explanation to support the proposed ratios of area treated to area under VM during the test periods, which are significantly higher. The RPG recommended that the proposed VM costs be scaled to reflect the average ratio of area treated to area under VM during 2010 to 2013 period, and that ATCO Electric's forecast VM costs for the test period be reduced by $5.2 million in 2015, $4.9 million in 2016 and $5.3 million in 2017, as calculated in the table below:[191]

Table 13. RPG recommended vegetation management reduction

	2015	2016	2017
Proposed ratio area treated to area under VM	8.6%	6.9%	7.6%
RPG estimated ratio of area treated to area under VM 2010-2013	3.8%	3.8%	3.8%
Area Under VM (thousands of square metres)	231,093	267,952	271,822
Area treated based on 3.8% ratio (thousands of square metres)	8,782	10,182	10,329
Proposed cost ($ million)	9.3	11.0	10.5
Proposed cost scaled to reflect 2010-2013 average ratio of 3.8% ($ million)	4.1	6.1	5.3
RPG recommended reduction ($ million)	5.2	4.9	5.3

Source: Exhibit 20272-X1297, RPG argument, recommended reduction to VM, paragraph 328, PDF pages 109-110.

252. In its argument, ATCO Electric stated that its VM program is integral to the safe and reliable operation of its transmission system, and the VM forecast was a direct result of patrols

[191] Exhibit 20272-X1297, RPG argument, paragraphs 324-332, pages PDF 108-111.

that were completed on approximately two-thirds of its rights-of-ways. ATCO Electric argued that a forecast based on an average of the amounts spent in 2012-2014 would not reflect the current conditions on those rights-of-way, as assessed by professional foresters patrolling the rights-of-way and determining the required treatments. The utility argued that the RPG's approach also ignores unexpected and unusual circumstances that ATCO Electric experienced in executing its VM program in 2014 and 2015.[192]

253. ATCO Electric acknowledged that it had forecasted a significant increase in the number of square metres to be treated during the test period, but attributed this to a number of factors including favourable growing conditions experienced on a number of its rights-of-way; the repopulation of vegetation in certain areas; and increased stem density resulting from difficulty it experienced in using herbicides in the past. ATCO Electric stated that it has recently experienced less difficulty with herbicide use, and has been able to build-up contractor capability. As a result, it was able to successfully deploy herbicide methods during 2015 and anticipates that it will continue to be able to do so in the remainder of the test period.[193]

Commission findings

254. ATCO Electric identified an error in its VM forecast and provided an update for 2016 and 2017 during the oral hearing.[194]

> A. MS. CLARK: On February 23rd, ATCO Electric filed an update to the application, including a set of updated schedules as Exhibit 20272 (verbatim), Exhibit 1101. And it came to our attention that in respect to the uniform system of account, Number 571.1, vegetation management, the numbers included in that schedule did not reflect the latest inflationary assumption that we incorporated into the remainder of the filing, and so updated numbers that should appear on line 7 of that schedule are $10.8 million for 2016, and that is an update from the original -- or from the filed 11.01; and 2017 should be 10.0, as opposed to the 10.5 that is shown in that schedule.

255. In IR AET-AUC-2015DECEMBER30-010(b), the Commission made the following request of ATCO Electric:

> Please provide detailed vegetation management information by line number and substation, using the format shown below, showing actuals for each of the years 2012, 2013, 2014 and 2015 (for the months available) along with the 2012, 2013 and 2014 approved forecast, as well as the updated forecast for each of 2015, 2016 and 2017 test periods.

Line number	Year work deferred from (if applicable)	Method (trim, slash, mow, spray)	Km of line cleared	m^2 (000's)	Unit cost ($/m2)	$ (million)
Substation number	Year work deferred from (if applicable)	Method (trim, slash, mow, spray)		m^2 (000's)	Unit cost ($/$m^2$)	$ (million)

[192] Exhibit 20272-X1298, paragraph 84, PDF pages 42-43.
[193] Exhibit 20272-X1298, paragraphs 85-87, PDF pages 43-44.
[194] Transcript, Volume 1, page 17, lines 4-16.

256. The Commission provided a summary of ATCO Electric's response to AET-AUC-2015DECEMBER30-010(b), in an aid to questioning,[195] as reproduced below:

Table 14. Analysis of actual vegetation management work done versus forecast

	Current year planned work	Work deferred from prior years	Total	% of actual forecasted current year planned work done
2012 actual	1.42	2.27	3.70	34.4%
2012 forecast	4.13	0.06	4.19	
2013 actual	3.18	0.67	3.84	96.0%
2013 forecast	3.31	0.93	4.24	
2014 actual	1.06	0.85	1.91	23.4%
2014 forecast	4.54	0.03	4.58	
2015 actual	4.38	2.78	7.16	
2015 forecast	-	-	-	
2016 forecast	5.04	3.28	8.32	
2017 forecast	7.17	0.25	7.42	
			3-year avg.	47.2%

Source: Exhibit 20272-X1196, aid to questioning, PDF page 1.

Table 15. Analysis of actual volume of vegetation management work done versus forecast

	Current year planned work	Work deferred from prior years	Total	% of actual forecasted current year planned work done
2012 actual	2,734,924.55	5,403,369.45	8,138,294.00	34.1%
2012 forecast	8,018,839.00	101,161.00	8,120,000.00	
2013 actual	6,746,053.00	1,922,311.00	8,668,364.00	82.3%
2013 forecast	8,193,360.00	2,764,567.00	10,957,927.00	
2014 actual	2,123,504.10	2,004,189.00	4,127,693.10	18.1%
2014 forecast	11,731,299.00	168,997.00	11,900,296.00	
2015 actual	11,626,909.00	8,179,658.00	19,806,567.00	
2015 forecast	-	-	-	
2016 forecast	10,976,952.23	7,603,819.86	18,580,772.10	
2017 forecast	20,033,372.85	500,000.00	20,533,372.85	
			3-year avg.	41.5%

Source: Exhibit 20272-X1196, aid to questioning, PDF page 2.

257. These tables provide a comparison of (1) the actual dollars spent for VM work performed on lines and trim inventory relative to forecast, to (2) the actual volume of VM work performed on lines and trim inventory relative to forecast. The above tables confirm that a significant amount of work reflected in ATCO Electric's 2015 actuals and 2016 forecasts was deferred from

[195] Exhibit 20272-X1196.

prior years ($2.8 million of $7.2 million in 2015 and $3.3 million of $8.3 million in 2016, respectively).

258. It is clear that work deferred from prior years is driving a large part of the increase in 2015 actual expenditures and 2016 forecast expenditures. The Commission considers that the adoption of the RPG's recommended approach would limit test year forecasts to past period actuals, effectively ignoring the growing backlog of deferred work that must be performed resulting in an underestimation of the utility's revenue requirement. The Commission also finds that this approach ignores the unexpected and unusual circumstances that ATCO Electric experienced in executing its vegetation management program in recent years.

259. The Commission is troubled by the observed historical variances between work forecasted and actual work done on ATCO Electric's lines. While the Commission is prepared to accept the volume of work that needs to be performed, as confirmed by professional foresters, it remains uncertain as to ATCO Electric's ability to complete the forecasted work during the test period.

260. ATCO Electric explained that it was unable to execute its full VM program in 2014 because a key contractor unexpectedly left the marketplace. However, it continued to experience contractor-related difficulties in 2015. Additionally, in its response to the Commission's December 4, 2015 ruling letter, ATCO Electric provided the following reason for deferring $5.6 million dollars in VM expenditures planned for 2015 to 2016:

> In addition to adjusting for workforce reductions, AET is providing an updated forecast for vegetation management as outlined in the following table. Since the Omissions and Updates filing, elements of the vegetation management program have been delayed. Two of the contractors AET planned to use to execute vegetation management work advanced from 2016 experienced serious safety incidents in October that required a shutdown of several weeks in duration to accommodate a thorough investigation and implementation of measures to prevent recurrence. AET will also be unable to complete a portion of the mechanical programs included in the original GTA forecast. The frozen ground conditions required to facilitate access to these programs did not materialize due to the extremely warm weather experienced in the fall of 2015, resulting in a deferral of these programs to early 2016 for execution. There are no adjustments to overall treatment volumes forecast to be completed between 2015 and 2016 from those previously reported in AET's October O&U filing. This update only impacts the timing of completion of the Vegetation Management work. AET is revising its O&U forecast to defer vegetation management work from 2015 to 2016.[196]

261. It appears to the Commission that ATCO Electric, in addition to being unable to control the weather and resulting growing seasons, is unable to reasonably rely on the availability of contractors to perform the work it has forecasted. The Commission considers that ATCO Electric's customers should not bear a disproportionate share of the risk that ATCO Electric may be unable to complete its forecasted VM work. Therefore, the Commission directs ATCO Electric to set up a reserve account for vegetation management in its no cost capital schedules in Section 29 of its revenue requirement schedules. Regarding the mechanics of the reserve account, ATCO Electric will be required to set off amounts spent in excess of approved forecasts for a given test year against amounts included in approved forecasts for subsequent years within

[196] Exhibit 20272-X0700, page 3.

the test period. Approved, but unused, VM amounts in any given GTA test period will be added to the VM reserve account for the next GTA test period.

262. The Commission considers that the size of the required reduction is reasonably informed both by the nature of the shortcomings identified in the currently proposed forecasts and observed historical variances from previously approved forecasts. As shown in the preceding table, the average observed variance to transmission line volume to be cleared is approximately 60 per cent of forecast over three years. This variance amount represents 30 per cent of the total 2016 VM costs forecasted by ATCO Electric. On this basis, the Commission considers it likely that some portion of VM work forecast for 2016 will be deferred into 2017. For forecasting purposes, the Commission considers that the application of a 25 per cent reduction to 2016 and 2017 VM forecasts is reasonable.

7.3 Telecommunication costs

263. ATCO Electric proposed to change the method it uses to allocate telecommunication network costs.[197] ATCO Electric has previously allocated telecommunication network O&M and capital costs based on the percentage of data traffic. It explained in its 2013-2014 GTA that this resulted in costs being allocated equally between ATCO Electric Transmission and ATCO Electric Distribution.[198]

264. The methodology ATCO Electric proposes to use for the 2015-2017 test years would increase its allocated percentage of telecommunication O&M costs to 100 per cent, subject to a revenue offset obtained by charging ATCO Electric Distribution the costs associated with servicing its telecommunication equipment and network usage. Table 9 below outlines the cost impact of the proposed change.[199]

Table 16. Comparison of telecommunication forecast O&M cost allocations

	2015 test period	**2016 test period**	**2017 test period**
	($ million)		
Total telecommunication O&M costs	6.3	8.8	9.3
Recovery from AED payment – prior allocation method	3.0	4.3	4.5
Revenue offset from AED – proposed allocation method (Note)	1.3	1.4	1.5

Note: The revenue offset values include overhead.
Source: Exhibit 20272-X1100, page 5-11, PDF page 73.

265. ATCO Electric stated that the proposed change in how telecommunication costs are allocated will achieve two objectives. First, it will ensure that the treatment of telecommunication costs is aligned with the main functions and obligations of the telecommunication network as defined in legislation.[200] Second, it will ensure consistent treatment for market participants across Alberta.[201]

[197] Exhibit 20272-X1100, revised application, page 1-7, PFD page 7.
[198] Exhibit 20272-X1100, revised application, paragraph 133, PDF page 73.
[199] Exhibit 20272-X1100, revised application, paragraph 133, PDF page 73.
[200] Exhibit 20272-X1100, revised application, paragraph 135, PDF page 74.
[201] Exhibit 20272-X1100, revised application, paragraph 138, PDF page 74

266. ATCO Electric argued that telecommunications are integral to the safe and reliable operation of the transmission network, and that telecommunications is included in the definition of "transmission facility" in the *Electric Utilities Act*.[202] ATCO went on to assert that "[s]ince telecommunication facilities are viewed as transmission related infrastructure under the EUA [*Electric Utilities Act*], to the extent that such facilities serve the purpose of ensuring safe and reliable operation of the transmission network, the full costs associated with operating and maintaining that infrastructure should be included in transmission revenue requirement."[203]

267. ATCO Electric also argued that Section 29 of the *Electric Utilities Act* requires that market participants be given equal access to the telecommunication network.

268. ATCO Electric stated that it has transported data required for transmission network operations for generators, industrial systems and other TFOs on its telecommunication network at no additional charge beyond the transmission tariffs paid by those market participants. For equipment that was installed specifically for a market participant, the maintenance costs are directly recovered from that market participant. ATCO Electric argued that its proposed telecommunication cost allocation method treats ATCO Electric Distribution the same as other market participants.[204]

269. ATCO Electric explained that the cost to build and maintain the transmission telecommunication network is its responsibility under the proposed methodology. Costs for services provided by ATCO Electric Transmission personnel working on ATCO Electric Distribution communication equipment are proposed to be recovered through affiliate charges. The cost to transport ATCO Electric Distribution data, including metering data, will be recovered through charges that are based on market rates for circuit and tower rentals. Based on historical experience, ATCO Electric determined that the charges to its distribution affiliate would be approximately 12 per cent of its overall telecommunication O&M costs.

270. The UCA expressed a number of concerns with ATCO Electric's proposed allocation methodology. It claimed that with ATCO Electric Distribution being under performance- based regulation (PBR) and ATCO Electric Transmission being under cost of service regulation, a reduction in charges recovered from ATCO Electric Distribution would result in higher costs to ATCO Electric Transmission customers. The UCA also noted that savings achieved by ATCO Electric Distribution under this approach are not realized by its customers, but instead flow through to its shareholders.[205] The UCA calculated that the overall result would be an additional $2.1 million in rates paid by ATCO Electric customers, as illustrated below.[206]

[202] Exhibit 20272-X1100, revised application, paragraph 136, PDF page 74.
[203] Exhibit 20272-X1100, revised application, paragraph 137, PDF page 74.
[204] Exhibit 20272-X1100, revised application, paragraph 140, PDF page 75.
[205] Exhibit 20272-X0777, UCA evidence, A15, PDF page 10.
[206] Exhibit 20272-X0777, UCA evidence, A17, PDF pages 12-13.

Table 17. UCA Calculation of telecommunication cost over recovery

	2012	2013	2014	2015	2016	2017
Total telecommunication O&M costs	6.5	6.2	6.2	8.6	9.2	9.5
Recovery from AED payments - prior allocation method	3.1	3.8	2.7			
Revenue offset from AED - proposed allocation method				1.3	1.4	1.5
Net recovery from AET customers	3.4	2.4	3.5	7.3	7.8	8
Included in AED rates	3.3	3.36	3.41	3.46	3.51	3.56
Total telecommunication O&M costs paid by customers	6.7	5.76	6.91	10.76	11.31	11.56
Difference between the total telecommunication costs and costs paid by customers	0.2	-0.44	0.71	2.16	2.11	2.06

Source: Exhibit 20272-X0777, UCA evidence, PDF page 13.

271. The UCA also disputed ATCO Electric's statement that the information it provided with respect to tower rentals and individual circuits was confirmed by a market assessment.[207] It further argued that ATCO Electric Transmission provided quotes for individual circuits that provided a 10 per cent discount to ATCO Gas and ATCO Electric Distribution, both PBR utilities, with savings going to the benefit of shareholders.[208]

272. The UCA recommended that the Commission reject ATCO Electric's proposed methodology because it results in customers paying more in rates than the actual cost of telecommunication services. It also claimed that ATCO Electric had not proven that the rates it proposed to charge to ATCO Distribution would be at market value. The UCA suggested that the next test period would be a more useful time to bring forward the proposed allocation method for consideration because it would coincide with PBR rebasing. It proposed an alternative allocation method for this test period that would allocate costs between transmission and distribution based on the average of the prior three years' actual recoveries (2012 to 2014).[209]

273. In rebuttal, ATCO Electric noted that the information contained in the table provided by the UCA did not reflect updates to ATCO Electric's application, which updated information is provided in the table below:[210]

Table 18. ATCO Electric forecast of telecommunication costs

	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast	2017 forecast
	($ million)					
Total telecommunication O&M costs	6.5	6.2	6.2	6.3	8.8	9.3
Recovery from AED payment – prior allocation method	3.1	3.8	2.7	3.0	4.3	4.5
Revenue offset from AED – proposed allocation method	N/A	N/A	N/A	1.3	1.4	1.5

Source: Exhibit 20272-X1120, ATCO rebuttal evidence, PDF page 203.

274. ATCO Electric disagreed that consideration of the proposed allocation methodology should be deferred until the next test period to coincide with PBR rebasing and emphasized that ATCO Electric's distribution arm operates under a different regulatory regime. ATCO Electric

[207] Exhibit 20272-X0777, UCA evidence, A19, PDF pages 14-15.
[208] Exhibit 20272-X0777, UCA evidence, A20, PDF pages 15-16.
[209] Exhibit 20272-X0777, UCA evidence, A21, PDF pages 16-17.
[210] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 203.

argued that the UCA was attempting to affect its distribution affiliate's revenues mid-way through its PBR term, which is inconsistent with PBR principles. ATCO Electric emphasized that its proposed methodology provides the right signal to the distribution utility to find efficiencies to reduce telecommunication costs.[211]

275. ATCO Electric stated that its proposed treatment of telecommunication costs is intended to provide price signals consistent with the marketplace to encourage efficient outcomes. ATCO Electric argued that transmission ratepayers benefit when distribution operations use the transmission telecommunication network and pay for that service because the revenue associated with provision of the service is used to offset ATCO Electric's costs, thereby reducing rates for transmission customers. ATCO Electric also claimed that it provides a competitive price signal ensuring that both transmission and distribution customers benefit from the arrangement by offering a discount of 10 per cent to its distribution affiliate for use of its telecommunication network. According to ATCO Electric the "new method provides a simple and appropriate cost signal at fair market value and allows PBR regulated companies to make the most prudent decisions."[212]

276. The UCA argued that ATCO Electric's distribution arm has consistently used the telecommunication network at the established rates and there was nothing to suggest that it would cease to do so if it was not given a 10 per cent discount. The UCA added that if the Commission were to accept the proposed allocation change, it should not include the 10 per cent discount.[213]

277. The UCA reiterated its concern regarding the timing of the proposed change in methodology and the potential double- or over-recovery of costs in revenue requirement that could result from ATCO Electric Transmission being regulated under a cost of service framework, and ATCO Electric Distribution being regulated under a PBR framework.[214]

278. The UCA provided the following excerpt from Decision 20407-D01-2016[215] with respect to double recovery:[216]

> 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 manner.
>
> 173. The Commission generally agrees with EPCOR that under the PBR framework based on the l-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

[211] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 204.
[212] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 204-205.
[213] Exhibit 20272-X1296, UCA argument, paragraph 9, PDF page 6.
[214] Exhibit 20272-X1296, UCA argument, paragraph 11, PDF page 7.
[215] 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.
[216] Decision 20407-D01-2016, paragraphs 172-175.

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 l-X mechanism to that part of the regime which is governed by capital trackers, although there are mechanisms in place that dissuade that incentive. 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.

175. However, the Commission agrees with the CCA's view, supported by the UCA, 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. 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.

279. The UCA recommended that the current allocation methodology should continue to be applied to telecommunication costs for the remainder of ATCO Electric Distribution's PBR term. In its view, this will ensure that no over-recovery of telecommunication costs occurs. The UCA stated that it may be receptive to using the new allocation methodology at the end of the distribution PBR term for the calculation of ATCO Electric Distribution's new going-in rates (subject to its stated concerns regarding the 10 per cent discount).[217]

280. ATCO Electric argued that the telecommunications needs of its transmission and distribution operations are different, and submitted that, under the current cost allocation, distribution is paying very high prices for telecommunication services when there are less expensive alternatives available to it. ATCO Electric stated that it would have to incur 100 per cent of the telecommunications system costs if the distribution group decided to use a third party provider.[218]

281. ATCO Electric submitted that differences in the regulatory regimes applicable to transmission and distribution functions should not affect the choice of cost allocation methodology in this case. It claimed that incentives for correct behaviour need to be created by pricing signals in both cases.[219]

282. The UCA challenged ATCO Electric's assertion that "parties are not necessarily disputing the position that the proposed treatment of telecommunication costs and the resultant amount to be paid by ATCO Electric Distribution ("AED") is unreasonable." The UCA stated

[217] Exhibit 20272-X1296, UCA argument, paragraph 16, PDF page 10.
[218] Exhibit 20272-X1298, ATCO Electric argument, paragraph 78, PDF page 40.
[219] Exhibit 20272-X1298, ATCO Electric argument, paragraph 79, PDF pages 40-41.

that it has two concerns with respect to ATCO Electric's proposed treatment of telecommunication costs:[220]

> a. The inclusion of a 10 per cent discount in the proposed new allocation methodology is not reasonable, and would result in rates that are not fair and reasonable; and
>
> b. The timing of the implementation of the proposed new allocation methodology is not reasonable, and would result in rates that are not fair and reasonable.

283. The UCA stated in reply argument that the telecommunication system has always been fully required for transmission purposes, and that this does not provide a basis upon which to change the allocation methodology for transmission without making a corresponding change for distribution.[221] The UCA also reaffirmed its position that the currently approved cost allocation methodology should remain in place until there is a rebasing of ATCO Electric Distribution costs.[222]

284. ATCO Electric argued that interveners do not appear to dispute that charging distribution approximately 12 per cent of telecommunication costs is fair and reasonable. Instead, they take issue with the proposed allocation on the basis that ATCO Electric's transmission and distribution utilities are under different regulatory systems, and point to the potential for double- or over-recovery of costs from customers.[223]

285. ATCO Electric stated that the UCA's position ignores a fundamental premise underpinning PBR, which is that it is entirely inappropriate to attempt to examine a single cost line item and link it to revenues. ATCO Electric provided several references to prior Commission decisions confirming this.[224]

286. ATCO Electric noted that costs incurred by its distribution utility will be examined at a later date as part of the PBR rebasing process. It also argued that the fact that its distribution utility is regulated under PBR provides no basis for rejecting its proposed cost allocation methodology for its transmission operations.[225]

287. Finally, ATCO Electric submitted that the EDTI decision cited by the UCA as reflecting the Commission's concerns regarding the potential for double- or over-recovery for PBR utilities is distinguishable from the current situation where the Commission is dealing with two different entities under two different regulatory systems.[226]

Commission findings

288. The definition of "transmission facility" contained in the *Electric Utilities Act* includes "operational, telecommunication and control devices."[227] In this application, the Commission must determine the reasonableness of the costs forecasted to be incurred by ATCO Electric in the

[220] Exhibit 20272-X1305, UCA reply argument, paragraph 9, PDF pages 5-6.
[221] Exhibit 20272-X1305, UCA reply argument, paragraph 13, PDF page 7.
[222] Exhibit 20272-X1305, UCA reply argument, paragraph 14, PDF pages 7-8.
[223] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 74, PDF pages 35-36.
[224] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 75, PDF page 36.
[225] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 76, PDF pages 36-27.
[226] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 77, PDF page 37.
[227] *Electric Utilities Act*, Section 1, c E-5.1, Section 1(bbb)(iv).

performance of its transmission function. Part of that function includes the operation of its telecommunications system. ATCO Electric Ltd.'s distribution arm has historically used the telecommunications system subject to a cost allocation methodology that divided the costs of operating the system proportionally between distribution and transmission functions. The Commission notes that the original cost allocation was 60 per cent to transmission and 40 per cent to distribution and is currently approximately 50/50. These allocations were previously approved by the Commission and are based, in part, on a consideration of the amount of data traffic attributable to each entity. Such shared services arrangements are contemplated by the ATCO Inter-Affiliate Code of Conduct, which permits them to operate subject to the requirement that each involved affiliate must bear its proportionate share of operating costs.[228]

289. ATCO Electric distribution's going-in rates for the current PBR plan reflected a 40 per cent cost allocation for telecommunications services, as approved by the Commission in Decision 2011-134, dealing with ATCO Electric's 2011-2012 GTA. Subsequently, in Decision 2013-358, the Commission approved an updated cost allocation for telecommunications services pursuant to which ATCO Electric's transmission and distribution operations contribute equally to the expense of operating the system. ATCO Electric proposed to extend a 10 per cent discount to its distribution arm to incent it to continue to use the system that was constructed by the transmission division. It argued that this incentive is required to ensure that transmission customers do not lose the benefit of revenue offsets obtained from distribution revenues were the distribution division to look elsewhere for lower priced services.

290. The Commission is not persuaded that the new cost allocation proposed by ATCO Electric is reasonable in the circumstances. The present cost allocation methodology results in just and reasonable rates for both ATCO Electric Ltd.'s transmission and distribution customers.

291. The Commission finds for the reasons below, that the proposed reallocation of telecommunications costs between ATCO Electric Ltd.'s transmission and distribution divisions would not result in just and reasonable rates. Instead, it would create a situation in which double-recovery of telecommunications costs would occur at the expense of transmission customers. This is because ATCO Electric distribution's existing PBR rates, which provide for recovery from distribution customers of approximately 50 per cent of the total telecommunications-related costs incurred by both the transmission and distribution divisions, would persist despite the fact that the transmission division's cost allocation would be altered. One consequence would be that the distribution function would have its related cash flow supplemented in the PBR environment since it would no longer be required to spend amounts still being recovered in its rates to pay for telecommunications costs. A second, and more serious, consequence of the proposed arrangement is that transmission customers would bear an additional rate burden arising from revenue shortfalls caused by the reallocation, while distribution customers continue to pay amounts that would otherwise be allocated to cover this cost. ATCO Electric expressed the view that differences in the regulatory regimes applicable to transmission and distribution functions should not affect the choice of cost allocation methodology. The Commission disagrees. In this case, the interplay between one regulated entity that is subject to cost-of-service regulation and another that is under PBR can result in the double-counting of costs to the detriment of transmission customers. The Commission cannot permit this to occur in establishing just and reasonable rates.

[228] ATCO Inter-Affiliate Code of Conduct, Section 3.3.4.

292. The Commission also has concerns with approving a 10 per cent discount to incent ATCO Electric's distribution division to continue using the system. The Commission finds that changing the existing cost allocation to provide ATCO Electric's distribution division a 10 per cent discount as a retention incentive is inconsistent with the wording and spirit of the ATCO Inter-Affiliate Code of Conduct. Section 3.3.4 of the code which states that:

> **3.3.4 Shared Services Permitted**
>
> Where a Utility determines it is prudent in operating its Utility business to do so, it may obtain Shared Services from, or provide Shared Services to, an Affiliate. Utilities shall periodically review the prudence of continuing Shared Services arrangements with a view to making any necessary adjustments to ensure that each of the Utilities and its Affiliates bears its proportional share of costs.

293. The Commission considers that the code's effectiveness as a means of preventing cross-subsidization between affiliates depends on the principled application of provisions such as the one reproduced above. Section 3.3.4 clearly states that utility affiliates' continued participation in shared services arrangements is contingent on each participant bearing "its proportional share of costs." In the Commission's view, the provision of a discount is necessarily at odds with this principle since the existence of a discount would necessarily imply that the recipient is paying less than it would otherwise be required to remit. The Commission is concerned that approval of such retention incentives for affiliates could result in the creation of perverse incentives in relationships governed by the code. For example, offers of discounted services may incent utility affiliates to enter into, or remain in, shared services relationships that may otherwise be considered by one or both of the parties to be of questionable prudence. The Commission considers that such an outcome would be inconsistent with the promotion of just and reasonable rates through application of the ATCO Inter-Affiliate Code of Conduct.

294. The Commission also finds that the approval of an allocation methodology incorporating the requested discount would potentially distort incentives otherwise applicable to ATCO Electric's distribution division under PBR. The Commission considers that one of the central requirements of current generation PBR is that cost allocation methods used to set going in rates for affected utilities cannot be altered during the PBR term absent exceptional circumstances. Permitting adjustment of these cost allocation methods once application of the I-X mechanism has begun can distort incentives by either lessening or increasing revenue constraints designed to promote the identification and exploitation of efficiencies, while facilitating the continued provision of safe and reliable utility service. The Commission finds that, in this case, the extension of the requested discount to ATCO Electric Ltd.'s distribution utility would have the same overall effect as a mid-term alteration to that entity's PBR rates. The result would be that the PBR utility, in this case ATCO Electric Ltd.'s distribution division, would be left with more revenue (captured as a result of collected-but-not-spent amounts) than contemplated by the level of its going in PBR rates. This, in turn, would result in ATCO Electric Ltd.'s distribution division realizing a level of recovery through rates that decreases its incentive to find other efficiencies to improve revenue. The potential that approval of inter-affiliate discounts would distort PBR incentives in this way is a compelling reason to refuse their implementation. It is also one which is not diminished by any risk that ATCO Electric Ltd.'s distribution division may procure its telecommunication services from another vendor and, consequently, deprive transmission customers of the revenue offset they now enjoy.

295. ATCO Electric's telecommunications system is not only utilized by its transmission and distribution operations. The Commission understands that a portion of the system's capacity, albeit a small one, is also used by AltaLink Management Ltd. (AML). In responding to a Commission IR, ATCO Electric stated that "[n]o revenue is received from AltaLink for access to the telecommunications network based on a reciprocal arrangement."[229] The Commission considers this to be evidence of the fact that access to the ATCO Electric telecommunications system is perceived as having value to other transmission service providers.

296. In view of the foregoing, the Commission rejects ATCO Electric's proposed telecommunication cost allocation methodology and directs it to continue to use the allocation percentages approved in its 2013-2014 GTA.

7.4 Property taxes

297. ATCO Electric submitted adjustments to property taxes in its O&U filing indicating that taxes (actual and forecast, as the case may be) declined in 2015 by $9.6 million, by $35.0 million in 2016 and by $24.9 million in 2017.[230]

298. There were no challenges to ATCO Electric's updated submission.

Commission finding

299. The Commission has not identified any areas of concern with respect to ATCO Electric's forecast of property taxes and notes that they are covered by a deferral account. The Commission approves the test year forecasts for property tax as filed in ATCO Electric's update.

8 Transmission depreciation

8.1 Views of ATCO Electric

300. ATCO Electric filed a depreciation study, prepared by Larry Kennedy of Gannett Fleming, Canada, ULC (Gannett Fleming). In its application, ATCO Electric used the depreciation parameters developed in the Gannett Fleming study, including the annual depreciation accrual rates recommended for 2015, 2016 and 2017.

301. The recommended depreciation parameters with respect to service life and Iowa curve (life-curve) and net salvage estimates were developed based on the straight line method using the equal life grouping procedure, and were applied on a whole life basis with any accumulated depreciation variances in excess of five per cent amortized over the composite remaining life of the assets as of December 31, 2013. Mr. Kennedy continued to recommend that a separate amortization of reserve differences calculation be undertaken with the resultant true-up to be recovered on an annual basis. These methodologies were consistent with those used by ATCO Electric and Mr. Kennedy in previous depreciation studies.

302. Mr. Kennedy conducted the depreciation study based on a traditional retirement rate analysis and net salvage study. These analyses were used in combination with professional judgment, a review of company practices and outlook as they relate to plant operation and retirement, a review of the company's upcoming capital and retirement projects, consideration of

[229] Exhibit 20272-X0284, AET-AUC-2015JUN08-024 b), page 6 of 14.
[230] Exhibit 20272-X0604, ATCO Electric O&U filing, page 5 of 42.

current transmission industry practices and Mr. Kennedy's knowledge of service lives and net salvage percentage estimates for other electric transmission utilities.[231]

303. Mr. Kennedy's use of peer utilities was described as a reasonableness check for the depreciation parameters developed through other analysis. With respect to the Gannett Fleming Iowa survivor curve fitting process, Mr. Kennedy considered that using a mathematical solution as a starting point, combined with a visual process to properly consider all relevant factors, is a robust process that results in superior curve-fitting results.[232]

304. Mr. Kennedy relied on a database that included actual plant data up to December 31, 2013 and forecast plant in service as of December 31, 2014, December 31, 2015 and December 31, 2016, in determining depreciation rates for the years 2015, 2016 and 2017. Further, Mr. Kennedy stated that, for four transmission accounts,[233] certain plant retirements and costs of retirement had been forecast over the test period and included in the depreciation study data for the purposes of determining both life-curve parameters and/or net salvage percentage estimates and annual depreciation rates. This aspect of the depreciation study will be discussed in greater detail later in this decision.

305. A summary of ATCO Electric's 2013-2014 actual and 2015-2017 forecast depreciation expense is provided in the following table:

Table 19. Schedule of transmission depreciation and amortization expense

Depreciation and amortization expense	2013 actual	2014 actual	2015 forecast	2016 forecast	2017 forecast
	($ million)				
Gross provision	104.4	132.0	225.9	312.2	325.9
Vehicle depreciation capitalized	(1.6)	(2.1)	(4.8)	(5.8)	(6.3)
Amortization of contributions	(4.7)	(6.6)	(8.9)	(10.1)	(12.2)
Total depreciation expense	**98.0**	**123.3**	**212.2**	**296.4**	**307.5**
Year-over-year increase in total depreciation expense			**88.9**	**84.2**	**11.1**

Source: Exhibit 20272-X1101, GTA Schedules, revised February 23, 2016, Schedule 6-1, lines 1-5.

306. The $88.9 million forecast increase in ATCO Electric's depreciation expense relative to 2014 actuals was due primarily to Gannett Fleming's proposed percentage increases in negative net salvage and changes to life-curve parameters which added approximately $57 million and $9 million, respectively, to depreciation expense. A $12 million increase in the annual amortization of reserve differences accounted for most of the remaining increase in 2015 with the balance of the increase due to capital additions.

307. The forecast increase in depreciation expense in 2016 of $84.2 million was due largely to the incorporation of a full year of depreciation expense of $71.3 million on the Eastern Alberta Transmission Line (EATL) project with the balance of the increase related to capital additions.[234]

[231] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, PDF pages 18-392.
[232] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 156 and 174, PDF pages 70 and 77.
[233] Account 451 (USA 350.1) – land rights, Account 453 (USA 355) – poles and fixtures (wooden), Account 454 (USA 356) – overhead conductors poles (wooden) and Account 457 (USA 353) – substation equipment – AC.
[234] Exhibit 20272-X1100, revised application narrative – clean, paragraph 251, PDF page 116.

308. In the depreciation study, Gannett Fleming proposed the creation of eight new depreciation study accounts, bringing the total number of accounts examined in the depreciation study to 27 excluding any asset accounts related to ATCO Electric's generation function. Of the eight new accounts proposed, one was the result of establishing a transmission – high-voltage, direct-current (HVDC) conductors-towers account; three were the result of further sub-componentization of transportation and tools and instrument accounts; and four were related to establishing leaseholds and various types of software as depreciation study accounts.

309. ATCO Electric proposed service life and/or survivor curve adjustments for 14 of its 19 current depreciation study accounts (excluding generation related assets) and proposed net salvage percentage adjustments for 10 of its 19 current depreciation study accounts. Separate life-curve and/or net salvage parameters were proposed by Gannett Fleming for each of the eight new depreciation study accounts.

8.2 Views of the parties

The RPG

310. The RPG filed depreciation evidence taking issue with the recommended life-curve and net salvage parameters for Account 455.1 (USA 354) – transmission – towers and fixtures (steel). The RPG recommended that comprehensive and independent studies be conducted to determine the probability of tower failures for use in establishing a revised estimate of service life for this account and to provide the basis for net salvage percentage estimates.

311. The RPG also recommended that assets comprising Account 455.1 (USA 354) – transmission – towers and fixtures (steel) that were built to comply with the higher functional specifications required in Independent System Operator (ISO) Rule 502.2, be placed in a separate asset account to permit the accumulation of data for depreciation study purposes.[235]

312. While the RPG evidence focused primarily on Account 455.1 (USA 354) – transmission – towers and fixtures (steel) and the effect that ISO Rule 502.2 would have on service life and net salvage considerations, it was of the view that ISO Rule 502.2 functional specifications would affect, albeit to a lesser degree, service life-curve parameters for Account 453 (USA 355) – transmission – poles and fixtures (wooden), Account 454 (USA 356) – transmission – overhead conductors and devices (wooden), and both service life and net salvage parameters for Account 454.10 (USA 356) – transmission – overhead conductors towers (steel) as well.[236]

313. During the oral hearing, RPG witnesses, Mr. Dan Levson and Mr. Trevor Cline, spoke to the depreciation-related aspects of the RPG's evidence.

314. The RPG submitted argument and reply argument with respect to the depreciation evidence filed in this proceeding and adopted most, if not all, of the recommendations made by Mr. Jacob Pous in his written evidence and oral testimony on behalf of the CCA.

315. The RPG submitted that key evidence provided in IR responses was not satisfactorily addressed by the members of ATCO Electric's depreciation panel during the oral hearing and, as a result, ATCO Electric failed to meet the onus it bears in justifying its depreciation rates.[237]

[235] Exhibit 20272-X0789, RPG evidence, paragraphs 245-246, PDF page 95.
[236] Exhibit 20272-X0811, RPG-AUC-2016FEB01-002(b), PDF pages 5-6.
[237] Exhibit 20272-X1297, RPG argument, paragraph 343, PDF page 113.

316. To address these concerns, the RPG recommended that in future proceedings the Commission adopt a number of modifications to the current process including: allowing further rounds of IRs on information filed by the applicant in IR responses; a minimum of four weeks for the preparation of intervener evidence following the last round of IR responses; and requiring the utility to make any staff (engineering, operations and management) associated with the depreciation study available for questions in advance of the IR process, as part of a technical workshop.[238]

The CCA

317. The CCA submitted evidence prepared by Mr. Jacob Pous of Diversified Utility Consultants, Inc. to address several depreciation issues and the reasonableness of ATCO Electric's requested depreciation provisions for 2015, 2016 and 2017, as developed by Gannett Fleming in its depreciation study.

318. Of the 27 depreciation accounts studied, the CCA challenged ATCO Electric's proposed changes for 10 of the accounts (accounts 451, 453, 454, 454.1, 455.1, 457, 457.1, 482, 496.1 and 496.2) related to service life-curve, or amortization periods and seven of the accounts (accounts 453, 455.1, 457, 457.1, 453.02, 457.02 and 482) related to net salvage percentages.[239]

319. In his written evidence, Mr. Pous stated that ATCO Electric was seeking material increases in depreciation expense during the test period but that its support and substantiation for the proposed increases was demonstrably inadequate for the accounts in question.

320. Mr. Pous also identified "macro" or "big picture" concerns with the depreciation process in Alberta compared to what he has observed elsewhere in North America. Specifically, Mr. Pous identified the following areas that "set the process in Alberta apart from elsewhere."

> (1) reliance on the equal life group ("ELG") calculation procedure, (2) normally a rather constrained time frame between the receipt of responses to discovery and submission of testimony, (3) normally the limitation of discovery to a single round, (4) a practice of allowing forecasted future retirements and additions to be utilized in the calculation of depreciation parameters, not just future plant balances, and (5) reliance on the whole life depreciation method in conjunction with the amortization of an excess reserve once a five percent threshold is reached, to name most of the major differences.[240]

321. Mr. Pous spoke to the evidence he filed on behalf of the CCA, but did not file argument or reply argument in this proceeding.

322. The Commission has summarized in the following table the impact of ATCO Electric's proposed depreciation parameters compared to approved depreciation parameters and the proposals of Mr. Pous.

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238 Exhibit 20272-X1297, RPG argument, paragraph 345, PDF page 114.

239 Exhibit 20272-X0780, evidence of Jack Pous, PDF page 5, indicates Mr. Pous recommended adjustments to service life for nine accounts and net salvage for six accounts, however the tables on PDF pages 18 and 60, indicate Mr. Pous recommended adjustments to service life for 10 accounts and net salvage for seven accounts.

240 Exhibit 20272-X0780, evidence of Jack Pous, PDF page 7.

Table 20. Comparison of impact of depreciation proposals based on forecast plant balances as of December 31, 2015, 2016 and 2017

Depreciation and amortization expense	2015	2016	2017
	($ million)		
ATCO Electric: depreciation expense using approved parameters (1)	134.3	185.5	193.7
ATCO Electric: depreciation expense using proposed parameters (2)	212.2	296.4	307.5
Increase in depreciation expense as a result of ATCO Electric's proposed parameters	**77.9**	**110.9**	**113.8**
CCA: depreciation expense using proposed parameters (3)	132.9	186.9	196.1
Decrease in ATCO Electric's proposed depreciation expense as a result of CCA's proposed parameters	**(79.3)**	**(109.5)**	**(111.4)**

Source: (1) Exhibit 20272-X1073, AET-AUC-2015JUN08-120-REVISED February 23, 2016, Schedule 6-1, line 6. (2) Exhibit 20272-X1101, GTA Schedules, revised February 23, 2016, Schedule 6-1, line 5. (3) Exhibit 20272-X0915, CCA-AUC-2016FEB01-018(a), column J, row 32 on each tab 2014, 2015 and 2016 which are applicable to the test years 2015, 2016 and 2017 respectively.

323. The following table compares, at an account level, the approved depreciation parameters and the parameters proposed by ATCO Electric and the CCA:

Table 21. Summary of approved and proposed depreciation parameters (excluding generation assets)

AET account	USA account	Description	Approved Decision 2011-134([241]) 2008 parameters (2011-2014)		ID 20272 AET proposed 2013 parameters (2015-2017)		ID 20272 CCA proposed 2015-2017 parameters	
			YFR/Int.Ret.		YFR/Int.Ret.		YFR/Int.Ret.	
			Life-Curve	N.S.	Life-Curve	N.S.	Life-Curve	N.S.
		Transmission facilities						
451	350.1	Land rights	75-R3	0%	73-R4	0%	100-R4	
453	355	Poles and fixtures (wooden)	55-R3	-90%	60-R2	-175%	63-R2	-90%
454	356	Overhead conductors poles (conductor wooden poles)	60-R4	-50%	65-R3	-50%	70-R2.5	
454.1	356	Overhead conductors towers (conductor steel towers)	60-R4	-20%	65-R4	-50%	70-R2.5	
455.1	354	Towers and fixtures (steel)	50-R4	-25%	65-R4	-200%	70-R4	-50%
457	353	Substation equipment - AC	53-R3	-10%	51-R2	-40%	56-R2	-15%
457.1	353	HVDC conductors-towers - HVDC (new)	n/a	n/a	53-R3	-40%	56-R2	-15%
		McNeill convertor station						
451.02	350.1	Land rights	2035 / 45-R4	0%	2035 / 45-R4	0%		
453.02	355	Poles and fixtures	2035 / 45-R3	-2%	2035 / 45-R3	-50%		-90%
454.02	356	Overhead conductors poles	2035 / 45-R3	-2%	2035 / 45-R3	-50%		
457.02	353	Substation equipment	2035 / 45-R2.5	-2%	2035 / 45-R2.5	-10%		-15%
		General plant						
482	390	Structures and improvements	55-R3	-5%	40-R2.5	-5%	50-R2.5	15%
483	391	Office furniture and equipment	15-R3	0%	15-SQ	0%		
483.2	391.1	Computer equipment and accessories	5-S0.5	0%	5-SQ	0%		
484.01	392.1	Transportation equipment - category 1	10-L1.5	10%	8-L1.5	10%		

[241] 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.

AET account	USA account	Description	Approved Decision 2011-134([241]) 2008 parameters (2011-2014) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 CCA proposed 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
484.02	392.2	Transportation equipment - category 2	12-L1	10%	9-L2	10%		
484.03	392.3	Transportation equipment - category 3	25-R3	20%	18-S0	5%		
484.04	392.4	Transportation equipment - category 4	12-R2	20%	10-L3	15%		
484.05	392.5	Transportation equipment - category 5 (new)	n/a	n/a	4-S3	5%		
484.06	392.6	Transportation equipment - category 6 (new)	n/a	n/a	8-S3	5%		
485.01	394	Tools and instruments - category 1	10-R2	0%	8-SQ	0%		
485.02	394.1	Tools and instruments - category 2 (new)	n/a	n/a	4-SQ	0%		
486	353.1	Communications structures and equipment	25-R2	0%	25-R2	-15%		
489	399.2	Leaseholds (new)	n/a	n/a	8-SQ	0%		
496.1	n/a	Software - major (new)	n/a	n/a	7-SQ	0%	10-SQ	
496.2	n/a	Software - minor (new)	n/a	n/a	5-SQ	0%	7-SQ	
496.3	n/a	Software - desktop (new)	n/a	n/a	3-SQ	0%		

Legend: YFR – year of final retirement; Int.Ret. – interim retirement; N.S. – net salvage.
Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3. Exhibit 20272-X0780, evidence of Jack Pous, Tables, PDF pages 18 and 60.

8.3 Consideration of specific depreciation concepts and methodologies as used in Alberta

324. The previous section provided an overview of the positions and concerns raised by each party with respect to depreciation.

325. In this section, the Commission will first address a number of observations and recommendations made by the applicant and other parties respecting depreciation concepts, processes and methodologies. The Commission will then examine three specific issues in greater detail: (1) the use of forecast data in the determination of depreciation parameters; (2) the use of the mid-year convention; and (3) the necessity for the separation of certain accounts into subaccount categories and the requirements for additional studies with respect to these accounts.

8.3.1 Consideration of general depreciation concepts, processes and methodologies

Goal of depreciation

326. In argument, ATCO Electric reiterated Mr. Kennedy's view that the role of a depreciation expert is to "try and get the life estimate and the cost recovery correct. Matters such as toll mitigation are outside the realm of depreciation."[242] ATCO Electric also expressed a concern that, in recent decisions, the Commission has used depreciation as a mechanism to determine whether the costs of assets should be eligible (or continue to be eligible) for recovery in certain circumstances. During the hearing, Mr. Kennedy confirmed that he has never seen depreciation used in this manner and submitted that, in his expert view, it should not be used to determine cost eligibility. Rather, depreciation is a mechanism to determine the allocation of costs that have

[242] Exhibit 20272-X1298, ATCO Electric argument, paragraph 119, PDF page 56.

already been deemed to be prudent and are eligible for recovery. He explained that, in his view, a depreciation expert's goal is to align the recovery period with the service life of the asset.

327. ATCO Electric stated that similar views were expressed by Mr. Pous, who confirmed that, as a general concept, depreciation is simply a mechanism to collect the capital cost of an asset over the forecast or expected useful life of that asset but that it does not speak to the prudency of the costs incurred nor their eligibility for recovery. ATCO Electric also pointed to Mr. Pous's admission of being unaware of any other jurisdiction that would mandate a retirement event -- if determined to be an extraordinary retirement -- to be to the account of the shareholder.

328. ATCO Electric submitted that it is "extremely concerned" the Commission has used depreciation to reverse earlier findings of prudently incurred costs simply because the forecast service life of an asset has not been precisely calculated – an approach to depreciation ATCO Electric considers to be "entirely inappropriate."[243]

Gradualism and moderation

329. In his written evidence, Mr. Kennedy stated that the "study has discontinued the previous gradual and moderate recognition of high negative net salvage indications in order that immediate recognition be incorporated in its depreciation rates to ensure proper recovery of net salvage costs over the life of the assets."[244]

330. During questioning by Commission counsel, Mr. Kennedy agreed that gradualism and moderation are the "most important consideration of what we do in [his] profession, being in the world of depreciation analysts."[245]

331. Mr. Kennedy then expanded on his premise that depreciation experts need to "get it right" and stated that the concepts of gradualism and moderation have crept into the topic of depreciation for the wrong reasons. Mr. Kennedy explained that, initially, the application of gradualism and moderation was intended to avoid the large swings in depreciation parameters that might otherwise result from short-term trends. He emphasized that more recently, however, the application of gradualism and moderation has been used "to do a little bit of toll management."[246]

332. In discussions with Commission counsel at the oral hearing, Mr. Kennedy disagreed that one of the goals of depreciation could be to add a degree of predictability and smoothing to cash impacts and stated that "unfortunately, in the last little while where depreciation is being maybe used as a mechanism to define the eligibility of cost recovery. Never has been, never should be that way. Depreciation is to determine the allocation of the costs that have already been deemed to be prudent costs and eligible for recovery."[247]

333. ATCO Electric argued that the Gannett Fleming study still incorporates the concepts of gradualism and moderation, but does so in light of actual data and other information available to it.

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[243] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 120-122, PDF pages 56-57.
[244] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, PDF page 24.
[245] Transcript, Volume 11, page 1989.
[246] Transcript, Volume 11, page 1992.
[247] Transcript, Volume 11, pages 1990-1991.

334. In reply, the RPG asserted that ATCO Electric had set aside the concepts of gradualism and moderation in recommending its proposed depreciation parameters in this application. It argued that this supported the rejection of ATCO Electric's proposed depreciation parameters in favour of the recommendations put forth by the RPG.[248]

Removal of net salvage (costs of retirement) in rates

335. During the oral hearing, the Chair questioned Mr. Kennedy about options for paying costs of retirement should those costs, in the future, be removed from depreciation rates to give effect to a policy choice that "customers who are getting the new stuff are going to have to pay to take the old stuff out."[249]

336. While Mr. Kennedy agreed with the technical aspect of this scenario, ATCO Electric stated in argument that there was no evidence in this proceeding to suggest that the long standing practice in Alberta of including costs of retirement in depreciation rate calculations should be discontinued.

337. ATCO Electric argued that the evidence supports the continuation of the long standing regulatory practice of recovering future costs of retirement (or costs of removal) over the service life of the assets.[250]

338. The RPG stated that, in this proceeding, it was not recommending the capitalization of cost of retirement as part of the cost of the future replacement asset. However, it considered that the option to do so could be assessed along with many other potential options in a generic depreciation proceeding.

339. The RPG clarified that, in light of Commission Member Lyttle's observations in a recent AltaLink decision[251] on the potential for intergenerational inequity with respect to depreciation, it considered the alternative treatment of costs of retirement through capitalization should be investigated.[252]

Necessity of re-examination of current depreciation methodologies: the average life group procedure and square survivor (SQ) curves

340. Mr. Pous criticized ATCO Electric's use of the equal life group (ELG) procedure for determining depreciation expense on the grounds that it is not a straight-line method of depreciation and that it violates mathematical standards when used to calculate depreciation rates for utility assets. Mr. Pous argued that neither theory nor reality support the proposition that the ELG procedure is the only mathematically correct method for determining capital recovery.

341. Mr. Pous stated that the use of ELG creates front-end loading of depreciation expense that, when combined with similar front-end loading of return and taxes on new capital additions,

[248] Exhibit 20272-X1307, RPG reply argument, paragraph 292, PDF page 83.
[249] Transcript, Volume 11, pages 2113-2114.
[250] Exhibit 20272-X1298, paragraphs 169-171, PDF pages 75-76.
[251] Decision 3524-D01-2016: AltaLink Management Ltd., 2015-2016 General Tariff Application, Proceeding 3524, Application 1611000-1, May 9, 2016, Section 6.5, PDF pages 94-97.
[252] Exhibit 20272-X1307, RPG reply argument, paragraphs 280 and 282, PDF pages 79-80.

results in a form of intergenerational inequity in that current generations of customers pay excessive costs compared to later generations of customers.[253]

342. During the oral hearing, Mr. Kennedy advocated for the precision inherent within the ELG procedure and explained that the estimated curve is based on the account history and is subdivided into accrual rates on the basis of the specific Iowa curve (as opposed to one overall rate associated with the average life group (ALG) procedure). Mr. Kennedy stated that cases where actual retirement activity does not match the shape of the Iowa curve is not evidence of an ELG problem but, rather, evidence of an average service life estimation problem.

343. Mr. Kennedy acknowledged that intervener consultants tend not to support the use of the ELG procedure. In his view, opponents consider it to be front-end loaded because the arithmetic results in a given asset having a higher depreciation rate and expense in the near term than in later years. According to Mr. Kennedy, this is simply an indication of the way that assets will expire and how the consumption of those assets should be matched to the depreciation rates.[254]

344. In argument, ATCO Electric asserted that the use of the ELG procedure provides more accurate matching of expected retirements of assets within an account and is considered by "virtually all authorities to be the most correct procedure to use for the depreciation of utility assets."[255]

345. The RPG recommended that the Commission direct ATCO Electric to refile its depreciation study using the ALG procedure rather than the ELG procedure. In its view, doing so would eliminate the front-end loading created by the ELG method and reduce ATCO Electric's applied-for depreciation expense between $3 million and $6 million during the test years.

346. The RPG recommended that, alternatively, the Commission could direct ATCO Electric to utilize square survivor curve (SQ) methodology for ISO Rule 502.2-compliant accounts in order to similarly address concerns related to front-end loading of depreciation expense flowing from use of the ELG procedure.[256]

347. The RPG acknowledged that it was cognizant of the Commission's finding in Decision 3524-D01-2016 regarding a similar recommendation. In that decision, the Commission held that a direction mandating the use of the ALG was outside of the scope of that specific proceeding. On that basis, the RPG stated that if the Commission was not willing to direct ATCO Electric to implement the ALG procedure as part of this proceeding, then this issue ought to be revisited as part of a broader generic depreciation proceeding.[257]

Need for a generic depreciation proceeding

348. The RPG recommended that the Commission initiate a generic depreciation proceeding that:

> i. Further defines and develops a standard list of minimum filing requirements that must be filed to support the requested depreciation expense;

[253] Exhibit 20272-X0780, evidence of J. Pous, PDF pages 8-10.
[254] Transcript, Volume 11, pages 2074-2077.
[255] Exhibit 20272-X1298, paragraph 207, PDF page 91.
[256] Exhibit 20272-X1297, RPG argument, paragraphs 400-401, PDF page 132.
[257] Exhibit 20272-X1307, RPG reply argument, paragraph 298, PDF page 84.

> ii. Create[s] a standard practice for including certain costs in specific USA codes across utilities to allow for benchmarking and across the province comparisons;
>
> iii. Review[s] the use of ELG and other possible depreciation procedures, techniques and methodologies across all Alberta utilities and asses[ses] the reasonableness of those as a group rather than in each individual utility proceeding; and
>
> iv. Review[s] the appropriateness of the whole-life technique in comparison to the remaining life technique, including the merits and costs of both options.[258]

349. The RPG's request in this regard was based, in part, on its view that the level of information provided by utilities in Alberta in support of their respective depreciation rates varies substantially from party to party.

350. ATCO Electric described the RPG's focus on topics that would fall under and culminate in a future generic depreciation proceeding as evidence that the issues raised by Mr. Pous and the RPG do not relate to the specific subject matter of ATCO Electric's 2015-2017 GTA. In ATCO Electric's view, these generic issues should not have any bearing on the matters before the Commission in this proceeding.

Commission findings

351. Many significant depreciation-related concepts were examined during the course of this proceeding. Several have been raised multiple times in prior applications before this Commission.

352. The Commission does not consider the goal of depreciation to have changed over time. It has traditionally been – and still remains – the primary mechanism by which a utility recovers its prudent investment in capital assets acquired to provide utility services.

353. In addition to the statistical analysis employed in depreciation studies, there are numerous tools and sources of information available to the Commission in testing the validity and reasonableness of parties' depreciation proposals. Peer analysis, professional depreciation and engineering expertise, manufacturers' information and the observations and comments of company personnel can also be considered in evidence to evaluate parties' recommendations for service life, Iowa curve and net salvage parameters.

354. The Commission is not currently prepared to order wholesale changes to depreciation concepts, processes and methodologies, such as gradualism and moderation and ALG or SQ methodologies, as such changes are beyond the scope of this proceeding

355. The issue of depreciation has gained significant attention in recent transmission tariff applications, in no small part due to the magnitude of the capital build in Alberta and the potentially very large incremental depreciation expense resulting from the addition of this capital to the regulated rate base of Alberta transmission utilities. Understandably, much of the discussion has focused on how depreciation is, or should be, calculated, and on the results and recommendations flowing from different depreciation studies.

356. Several parties in recent proceedings, including the instant one, have recommended that the Commission initiate a generic depreciation proceeding.

[258] Exhibit 20272-X1297, RPG argument, paragraph 346, PDF page 114.

357. The Commission will advise parties in due course should it determine such a proceeding to be necessary and in the public interest.

8.3.2 Use of forecast data in the determination of service life, Iowa curves and net salvage percentages

358. The Gannett Fleming depreciation study included forecast costs of retirement (where known) for upcoming projects as incorporated within the actuarial data relied on in its traditional net salvage study. Known upcoming retirement forecasts were similarly included in the actuarial data relied on by Mr. Kennedy for the purposes of the retirement rate analysis.[259]

359. Thus, the inclusion of forecast retirements of plant assets (at original historical cost) in addition to forecast costs of retirement were used to inform the analysis underlying the estimation of the depreciation parameters of service life, Iowa curve and net salvage percentages. This also informed the development of forecast plant balances and corresponding depreciation rates. Mr. Kennedy stated that in doing so, all known impacts of retirements could be considered.

360. The following table illustrates the quantum of forecast retirements and costs of retirement Gannett Fleming has incorporated into its depreciation study for the purposes of estimating both depreciation parameters and depreciation rates.

Table 22. Summary of forecast retirements and costs of retirement used in depreciation study for the purposes of establishing depreciation parameters

Account (USA Account) – description	Forecast retirements 2015-2017	Forecast costs of retirement 2015-2017
	($)	
451 (USA 350.1) – land rights	343,274	-
453 (USA 355) – poles and fixtures (wooden)	13,140,162	16,303,000
454 (USA 356) – overhead conductors poles (wooden poles)	4,458,130	5,876,000
457 (USA 353) – substation equipment - AC	18,000,216	23,021,000
Total used to establish depreciation parameters (X0621)	**34,941,782**	**45,200,000**

Source: Exhibit 20272-X0621, AET-AUC-2015OCT16-016, PDF page 4 of 776.

361. When asked in an IR if including forecast retirements and costs of retirement in data supporting depreciation parameter analysis constituted a departure from depreciation methodologies previously approved for use by ATCO Electric, Mr. Kennedy responded that including forecast information is not a change in depreciation methodology used by Gannett Fleming for ATCO Electric. In past depreciation studies, forecast additions were used by ATCO Electric to allow for better matching of forecast to actual depreciation expense.[260]

362. Gannet Fleming clarified its use of forecast capital additions in ATCO Electric depreciation studies in the following response to an undertaking:

[259] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, Revised 2014 Depreciation Study, pages I-4, II-3 to II-7, II-11: referencing transmission plant Account 451 (USA 350.1 – land rights, Account 453 (USA 355) – poles and fixtures (wooden poles), Account 454 (USA 356) – overhead conductors poles (wooden poles) and Account 568 (USA 353) – substation equipment – AC.

[260] Exhibit 20272-X0437, AET-AUC-2015JUN08-127(a-d), PDF pages 52-55.

> In prior depreciation studies, forecast capital additions were not used in the development of depreciation parameters. Forecast capital additions were only used in the calculation of depreciation rates in prior GTAs.[261]

363. During questioning by Commission counsel, Mr. Kennedy agreed that, historically, ATCO Electric had not incorporated forecast plant retirements in determining its depreciation rates. Mr. Kennedy explained that while including retirement data in the calculation of rates is useful, the forecast transaction must be identified by vintage in order to be considered for inclusion. Mr. Kennedy stated that given the high level of retirement activity forecast for the test years, he had recommended that ATCO Electric spend the time and effort to estimate the vintage of the assets forecast to be retired.[262]

364. Mr. Kennedy confirmed that the current depreciation study included forecast retirements and costs of retirement in the plant balances used to determine depreciation rates.[263]

365. Mr. Kennedy then offered the following qualification. The use of forecast retirements in this application, which he described as a response to an anticipated period of increased retirement activity, may in future revert to the long-standing practice of examining only historical transactions.[264]

366. Mr. Kennedy stated that he has always recommended including forecast retirement data in depreciation study databases for determining average service life and net salvage estimates. He cited AltaLink Management Ltd.'s three most recent depreciation studies as evidence of his past endorsement of the approach, and noted that these studies had received AUC approval. Further, Mr. Kennedy stated that, for the past 15 years, AltaGas Utilities Inc.'s depreciation studies have included forecast capital programs and retirements that likewise received AUC approval.[265]

367. When questioned about the consistency of use of forecast capital additions and retirement information, Mr. Kennedy stated that he "…would definitely say the use of the additional -- addition -- capital additions and forecast retirement information for the depreciation rate development is much more common than the inclusion of those – those transactions in the development of the depreciation parameter, being the average service life."[266]

368. Mr. Pous opposed using forecast data to determine depreciation parameters. He stated that in addition to issues with forecasting major capital projects and the required support, there was insufficient explanation or justification for how costs should be allocated between removing old plant and installing new replacement plant. Mr. Pous was also of the view that Mr. Kennedy's proposal to include forecast data in the development of depreciation parameters is inconsistent with industry practices and traditional analysis.

369. Mr. Pous stated that he was not aware of any regulatory body that has accepted the inclusion of forecast retirements or costs of retirement with the exception of cases, as noted in a

[261] Exhibit 20272-X1269, Undertaking 75 at Transcript, Volume 11, page 1954.
[262] Transcript, Volume 11, pages 1950-1952 and 1960.
[263] Exhibit 20272-X1298, paragraph 181, PDF page 80.
[264] Transcript, Volume 11, pages 1975-1976.
[265] Exhibit 20272-X0437, AET-AUC-2015JUN08-127(c)-(e), PDF pages 54-55.
[266] Transcript, Volume 11, page 1968.

NARUC publication, relating to interim additions of generation facilities, which often use depreciation methodologies incorporating life span analysis.[267]

370. With respect to forecast data being used in determining detailed depreciation rates for the years 2015, 2016 and 2017, Mr. Pous stated that doing so creates unnecessary calculations and complexities.[268]

371. According to Mr. Pous, issues associated with using forecasts to determine depreciation parameters and plant balances used in depreciation rates arise from insufficient certainty regarding the magnitude or the timing of the forecast expenditure. Mr. Pous stated that the information can only be captured with certainty in future depreciation studies after the (forecast) events have actually occurred.[269]

372. Mr. Pous stated that there was no widespread acceptance of forecasting test period plant balances used in depreciation rates but that it does happen. In his experience, the use of forecast data in the development of depreciation parameters was even less common. Mr. Pous stated that the problem with relying on forecasts is that they cannot be tested, add a layer of unpredictability, and require an understanding that the results will be used to "make a prediction for the future."[270]

373. The RPG stated that using forecast costs of retirement for upcoming retirement projects can lead to major distortions in both the retirement rate (service life) and net salvage analysis thereby contributing to incorrect estimates of average service life, Iowa curves and net salvage percentages. The major reason cited for variances between forecast and actual cost components was market conditions related to labour, material and commodity prices and changing project objectives. The RPG was not aware of any precedent for including forecasts of the nature identified by ATCO Electric in its depreciation study.[271]

374. ATCO Electric challenged Mr. Pous' claim that using forecast retirements is not a normal practice and stated that Mr. Kennedy had specifically pointed out that "this has been an accepted practice in Alberta and was a topic that was specifically reviewed and approved in a recent AltaGas Proceeding."[272]

375. The RPG recommended that the Commission direct ATCO Electric to file a revised depreciation study as part of its compliance filing by removing all forecast retirements from the study and instead providing depreciation information based only on historical information. In its view, the use of forecast retirements is not a normal practice because such forecasts, by their very nature, can alter the proposed depreciation parameter while still being subject to change. The RPG further recommended that the Commission direct ATCO Electric to file its future depreciation studies based only on historical databases.[273] [274]

[267] Exhibit 20272-X0912, CCA-AUC-2016FEB01-007(d), PDF pages 9-10.
[268] Exhibit 20272-X0912, CCA-AUC-2016FEB01-019, PDF pages 24-25.
[269] Transcript, Volume 11, pages 2128-2129.
[270] Transcript, Volume 12, pages 2142 and 2145.
[271] Exhibit 20272-X0811, RPG-AUC-2016FEB01-003, PDF pages 10-12.
[272] Exhibit 20272-X1309, paragraph 107, PDF 50.
[273] Exhibit 20272-X1297, RPG argument, paragraph 355, PDF page 116.
[274] Exhibit 20272-X1307, RPG reply argument, paragraph 286, PDF page 81.

Commission findings

376. In the Commission's view, there has been a measure of confusion between, and conflation of, the concept of forecasts being used to determine the *depreciation parameters* of average service life, Iowa curve and net salvage percentages, and forecasts being used to determine *depreciation rates*. The evidence put before the Commission has not consistently or clearly delineated between the two.

AltaGas example

377. In considering Mr. Kennedy's evidence with respect to past AltaGas regulatory proceedings, the Commission observes that in Decision 2005-127,[275] Directive 28 in respect of AltaGas' 2005-2006 GRA,[276] the EUB approved the use of 2005 and 2006 forecast plant balances to determine depreciation rates. In that case, the issue related to AltaGas basing its depreciation rates for the test years on forecast data as opposed to the last historical data year. The decision expressly noted that the historical aged vintage surviving balances had been determined on the basis of a computed mortality calculation, a practice used by AltaGas. AltaGas was directed to justify any future use of forecasts within its depreciation study at its next GRA.[277]

378. In a March 11, 2011 response to EUB Directive 28, Mr. Kennedy prepared additional evidence titled, "Use of forecast capital activity in the determination of depreciation rates."[278] In his evidence in this proceeding, Mr. Kennedy asserted that "the cases described above" provided a precedent for using forecast retirement activity in developing average service life estimates in circumstances of large retirement programs. The Commission observes, however, that Mr. Kennedy provided no specific references to verifiable cases involving the determination of average service lives, only references to the determination of depreciation rates.

379. Mr. Kennedy pointed to forecast capital activity being included in the depreciation rate calculations in AltaGas' negotiated settlement proceedings leading to Decision 2002-027,[279] Decision 2004-063[280] and Decision 2005-127, and the AltaLink proceeding leading to Decision 2007-019 [-012].[281]

380. With respect to forecasts used for determining depreciation parameters, Mr. Kennedy stated in his response to the directive that the forecast of compression equipment retirement was included in the average service life estimates in an NGTL depreciation study approved in Decision 2004-069.[282]

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275 Decision 2005-127: AltaGas Utilities Inc., 2005/2006 General Rate Application – Phase I, Application 1378000-1, November 29, 2005.
276 Application 1378000-1, AltaGas Utilities Inc. 2005-2006 GRA.
277 Decision 2005-127, pages 31-32.
278 Proceeding 904, Exhibit 0030.01.AUI-904, AUI 2010-2012 GRA Ph I, Tab 1.0, PDF pages 355-359.
279 AltaGas Utilities Inc. and Bonnyville Gas Company Limited, General Rate Application for Test Years 2000/2001/2002, Application 2000283 (1237650), File 1402-8, April 12, 2002.
280 Decision 2004-063: AltaGas Utilities Inc., 2003/2004 General Rate Application – Phase I, Request for Approval of Negotiated Settlement and Memorandum of Agreement, Application 1305995-1, August 3, 2004.
281 The Commission observes that the correct decision reference should have been to Decision 2007-012: AltaLink Management Ltd. / TransAlta Utilities Corporation, 2007/2008 TFO Tariff Application, Application 1456797-1; AltaLink Management Ltd., Settlement of Self Insurance Reserve Account for the Period, May 1, 2004 to December 31, 2005, Application 1468229-1, February 16, 2007.
282 Decision 2004-069: NOVA Gas Transmission Ltd., 2004 General Rate Application, Phase I, Application 1315423-1, August 24, 2004.

381. In evidence filed in Proceeding 904, the AltaGas Utilities Inc. 2010-2012 GRA, Mr. Kennedy summarily stated that "[t]he use of capital addition and retirement forecast[s] has been approved within the depreciation studies for utilities regulated by the AUC for a number of years."[283]

382. Gannett Fleming stated in its subsequent depreciation study for AltaGas' 2010-2012 GRA, that "[t]he depreciation rates developed in the depreciation study have been based on the forecast average of the plant in service balances over the period of December 31, 2010 through December 31, 2012."[284] And further that "[t]he estimated survivor curves and estimated net salvage per cents used in this report are based on studies incorporating data through 2009 for most accounts."[285]

383. In light of the foregoing, the Commission finds that Gannett Fleming has failed to clearly identify either the prior or continued use of forecast data for the purposes of developing depreciation parameters in past depreciation studies approved by this Commission.

AltaLink example

384. When questioned on the nature of the use of forecasts in depreciation studies at the ATCO Electric oral hearing, Mr. Kennedy stated the following with respect to AltaLink:

> In the case of AltaLink, AltaLink has always included in – not always -- in the last three cases for AltaLink have included the plant additions and retirements in the aged balance distribution that I used, not necessarily in the average service life estimation phase. We did include net salvage parameters in the life estimates in a case for AltaLink in I think it was 2009 that was allowed by this Commission.[286]
>
> …
>
> The -- in the cases of AltaLink, they were used in the retirement rate analysis and salvage analysis used in the determination of the depreciation parameters. And I say, there's -- that would be the case for at least the last three AltaLink proceedings.[287]

385. The Commission finds these statements, on a plain reading, to be contradictory and therefore cannot assign significant weight to the conclusions Mr. Kennedy draws from them.

386. The Commission has examined the most recent AltaLink depreciation study filed in Proceeding 3524 and concludes that AltaLink has not relied on forecast data in the manner depicted by Mr. Kennedy in his ATCO Electric evidence.

387. The Commission observes that AltaLink provided the following response, which was tendered in the oral hearing as an aid to questioning,[288] when asked to identify the years or parts of years in which actual, as opposed to forecast data, was used with respect to its depreciation study developing depreciation rates for its test years 2015 and 2016:

[283] Proceeding 904, Exhibit 0030.01.AUI-904, AUI 2010-2012 GRA Ph I, Tab 1.0, PDF page 357.
[284] Proceeding 904, Exhibit 0030.01.AUI-904, AUI 2010-2012 GRA Ph I, Tab 1.0, PDF page 356.
[285] Proceeding 904, Exhibit 0049.01.AUI-904, AUI 2010-2014 Depreciation study, PDF page 7.
[286] Transcript, Volume 11, page 1932.
[287] Transcript, Volume 11, page 1933.
[288] Exhibit 20272-X1237, AUC aid to questioning 10 – depreciation.

> Actual addition, retirement and net salvage data was used for vintage years 1941 through 2013 for the purposes of developing the average service life and net salvage estimates. However, forecasted additions and retirements were used for study years 2014 through 2016 which were used only in the calculation of the depreciation rates. Forecasted cost of removal and gross salvage were used for 2014.[289]

388. The Commission finds that the above-referenced statement does not support Mr. Kennedy's written and oral testimony in this proceeding concerning the use of forecast data for the purposes of developing depreciation parameters.

389. While the Commission agrees that it has approved the use of forecasts in the past, there is no clear evidence provided by parties that this has been allowed or definitively established for any purpose other than the development of depreciation rates as determined within a depreciation study and the course of a GTA.

390. The Commission does not agree that it is, or has been, standard depreciation methodology in this province to develop depreciation parameters on the basis of incorporating forecast retirements or costs of retirement into an actuarial data base that subsequently informs the retirement rate or traditional net salvage analysis.

391. The Commission has summarized at a high level, the evolution of ATCO Electric's 2014-2017 forecast/actual plant additions and retirements, net salvage and adjustments in the following table:

[289] Proceeding 3524, AltaLink 2015-2016 TFO GTA, Exhibit 3524-X0039, AML-AUC-2015JAN20-010(a), PDF page 20.

Table 23. Summary of transmission plant additions and retirements, net salvage and adjustments

Exhibit	Date	2014F	2014A	2015F	2015A	2016F	2017F	Total	
		($ million)							
Transmission plant additions:									
X0004	Mar-15	458.1		2,239.6		278.5	784.2	3,760.5	Schedule 10-2
X0599	Oct-15		451.2	2,139.3		293.2	515.9	3,399.6	Schedule 10-2
X1101	Feb-16		451.2	2,113.2		315.6	317.5	3,197.6	Schedule 10-2
X1264	Mar-16				2,144.0				Undertaking
Transmission plant retirements, net salvage and adjustments:									
X0004	Mar-15	40.1		19.9		15.6	4.2	79.9	Schedule 10-3
X0599	Oct-15		37.2	31.3		35.9	4.3	108.7	Schedule 10-3
X1101	Feb-16		37.2	31.3		35.9	4.3	108.7	Schedule 10-3
X1263	Mar-16				27.8				Undertaking
Transmission plant retirements, net salvage and adjustments used in retirement rate analysis* and/or net salvage study:									
X0621	Oct-15							80.1	PDF page 4

*In Exhibit 20272-X1246, Undertaking 79, Transcript, Volume 11, page 2030, Mr. Kennedy confirmed $18 million in plant retirements were not included in the retirement rate analysis for Account 457 - substation equipment - AC.
The $18 million is included in the $80.1 million figure shown above.

392. The Commission observes inconsistencies and problems associated with the use of the forecast information, as noted in the following paragraphs.

393. For example, as shown in Table 23 above, there is a disparity in the forecast retirements and net salvage that were used for the purposes of determining revenue requirement in the MFR schedules ($108.7 million) compared to the forecast retirements and net salvage ($80.1 million) used in the depreciation study.

394. Further, in response to an undertaking, ATCO Electric confirmed that for Account 457 (USA 353) – transmission – substation equipment – AC, forecast costs of retirement in the amount of $23 million and the associated retirement in the amount of $18 million were included in the traditional net salvage analysis, but the retirement in the amount of $18 million was excluded from the retirement rate analysis.[290]

395. In another example, in response to an undertaking, ATCO Electric confirmed that for Account 453 (USA 355) – transmission – poles and fixtures (wooden), forecast costs of retirement in the amount of $16.3 million for the test years were included in the traditional net salvage analysis conducted by Mr. Kennedy, and were subsequently updated to a $6.2 million forecast cost of retirement for the test years without a corresponding modification to the traditional net salvage analysis or the proposed net salvage parameter of -175.0 per cent.[291]

[290] Exhibit 20272-X1246, Undertaking 79, Transcript, Volume 11, page 2030.
[291] Exhibit 20272-X1262, Undertaking 76, Transcript, Volume 11, page 2018: Comparing Exhibit 20272-X0621, AET-AUC-2015OCT26-015, Attachment 1, page 2 of 2, PDF page 137 with Exhibit 20272-X0623, AET-AUC-2015OCT15-016, Attachment 1, PDF page 4.

396. Additionally, in examining the response to an IR providing a breakdown by account and by year of the forecast retirements, net salvage and adjustments that were included in the depreciation study, it is apparent that the largest impact from these forecasts is experienced in the 2015 and 2016 test years, but for the 2017 test year the forecasts have declined significantly to approximately 6.0 per cent of what had been forecast in the two prior years.[292] This can also be observed in Table 23, above.

397. The Commission considers that the above examples illustrate legitimate concerns with respect to the difficulties inherent in forecasting, generally, which are further complicated by the use of this information for the purposes of estimating depreciation parameters. The observed lack of consistency with respect to the data being used for one aspect of the depreciation study (for example, the net salvage analysis) but not another (for example, the retirement rate analysis), is concerning. Furthermore, the forecasts do not appear to reflect long-term trends. Instead, they appear to markedly decline in the 2017 test year. In the Commission's view, this phenomenon raises doubts as to the reasonableness of incorporating short-term trends into depreciation parameters that will remain in place until a new depreciation study is conducted. The Commission considers that the foregoing evidence highlights the difficulties alleged by Mr. Pous and the RPG to be directly associated with the proposal of ATCO Electric and Mr. Kennedy to include forecast information for the purposes of determining depreciation parameters.

398. The Commission also detects an inherent circularity in the proposal to use forecast information in developing depreciation parameters that are to be applied prospectively. The Commission prefers the use of consistent practices that result in stable outcomes based on verifiable events.

399. This is not to say that the Commission opposes or discourages the use of general information with respect to a utility's forecast capital programs involving asset retirements and associated costs of retirement. On the contrary, information of this type can improve management's knowledge and understanding of upcoming projects or programs and related decision making. In addition, sharing this information with a utility's depreciation expert can enhance the credibility of depreciation studies completed using such knowledge for the purpose of determining recommended depreciation parameters.

400. On the basis of the foregoing, the Commission denies ATCO Electric's proposed use of forecast information in its actuarial database for the purpose of developing depreciation parameters and directs ATCO Electric in its next depreciation study to revert to its currently approved methodology which provides for the use of forecast capital additions solely for the purpose of determining depreciation rates.

401. Having made this finding, and with respect to the four accounts affected by the above direction, the Commission, in subsequent sections of this decision, will evaluate the depreciation parameter proposals for the accounts in question, on the basis of other evidence provided by ATCO Electric and the intervening parties.

402. For the purposes of calculating its depreciation rates for the test years, ATCO Electric is directed in its compliance filing to this decision, to incorporate the capital additions approved

[292] Exhibit 202725-X0623, AET-AUC-2016OCT16-015, Attachment 1, PDF pages 136-137. Calculated from information on line numbers12 and 44 as ($4.3 / ($31.3+$35.9)).

elsewhere in this decision in calculating the aged plant account balances upon which each test year's depreciation rates will be based.

8.3.3 Use of the mid-year convention for assets placed into service in December

403. In response to an IR from the Commission, ATCO Electric advised that the EATL transmission line would be placed into service in December 2015 and would incur forecast depreciation expense in the amount of $36.7 million in the years 2015 and 2016, and $73.5 million in 2017.[293]

404. Subsequently, ATCO Electric was questioned about changes observed within its October 2, 2015 update filing. It responded that the original forecast of $36.7 million in 2015 depreciation expense for the EATL project was revised to assume no depreciation expense in 2015 and a full year depreciation expense of $73.5 million in 2016.[294]

405. During the oral hearing, Mr. Jansen explained in discussions with Commission counsel that ATCO Electric would normally use the mid-year convention consistent with its capitalization and depreciation policy. However, due to the magnitude of the dollars involved with the EATL project, the utility determined that the best forecasting approach would be to adjust the depreciation expense consistent with its financial accounting practices, that is, by recording depreciation expense in the month following capitalization. Mr. Jansen explained that this would align ATCO Electric's regulatory treatment with its financial treatment for the EATL assets by commencing depreciation expense in January 2016. He also confirmed that a full year of depreciation expense would be recorded for EATL in that calendar year.[295]

406. In a subsequent discussion with Commission member Lyttle, Mr. DeChamplain stated that as EATL is a direct assigned project and part of a deferral account:

> … it didn't make sense to include $36 million worth of depreciation in 2015 and then when we go to true it up with customers, just to give the $36 million back, because we knew we weren't going to have any actual depreciation in 2015. So what we did is we lowered the -- lowered the bar and we just updated the forecast and removed forecasted depreciation.[296]

407. The RPG recommended the Commission direct ATCO Electric in its compliance filing to file a list of all capital assets included in its application that are expected to be added into rate base in December of any test year. Further, the RPG requested that the Commission direct ATCO Electric to implement the same depreciation methodology employed by AltaLink to reduce what it argued was ATCO Electric's unfair over-earning on depreciation in each year. The RPG stated that such a direction would not treat ATCO Electric unfairly, but would provide for a fair payment of depreciation expense by customers.[297]

408. ATCO Electric argued that the exception to the mid-year convention for depreciation with respect to EATL represents the lowest revenue requirement for customers in 2015. This is because for direct assigned projects such as EATL, where there is no forecast risk for in-service dates, the actual recording of depreciation expense on capital additions in the month following

[293] Exhibit 20272-X0437, AET-AUC-2015JUN08-114, PDF pages 3-6.
[294] Exhibit 20272-X0623, AET-AUC-2015OCT16-013, PDF page 131.
[295] Transcript, Volume 11, pages 2080-2084.
[296] Transcript, Volume 11, page 2092.
[297] Exhibit 20272-X1297, RPG argument, paragraph 410, PDF page 134.

the project energization and capitalization reflects the actual depreciation expense incurred on that asset for the year and further aligns the revenues received in exchange for the service provided from those assets.[298]

Commission findings

409. The Commission is not persuaded that ATCO Electric's proposed transfer of $37 million of EATL-related depreciation expense into 2016, that otherwise would have formed part of ATCO Electric's 2015 revenue requirement, is reasonable.

410. ATCO Electric's proposal to reduce its 2015 revenue requirement by the same amount as its 2016 revenue requirement would increase, is not reasonable under the circumstances described, nor is it consistent with the mid-year convention used by other utilities regulated by the Commission. The Commission also finds that ATCO Electric's proposed treatment of EATL-related depreciation amounts is at odds with the provision of consistent and comparable year-over-year results for regulatory purposes.

411. The Commission is also concerned about the potential impact that ATCO Electric's proposed revenue shifting could have on other proceedings before the Commission where utility cash flows and their impact on credit metrics are at issue, such as the current 2016 GCOC proceeding. The Commission's concern is that artificial distortions of a utility's regulatory books arising from this kind of proposal could create an appearance of cash flow impairment where no such impairment potentially affecting a utility's credit metrics actually exists.

412. The Commission directs ATCO Electric to apply the mid-year convention in its revenue requirement calculations with respect to its depreciation expense calculations for all projects forecast to be capitalized in a given year and to reflect this direction in its compliance filing to this decision for regulatory purposes. In doing so, the utility is also directed to afford EATL-related depreciation mid-year convention treatment in respect of 2015, the year it was energized. ATCO Electric is further directed to continue applying the mid-year convention for regulatory purposes unless otherwise ordered by the Commission.

413. In light of the foregoing, there is no need for the Commission to consider the RPG's request that ATCO Electric provide a list of all capital assets included in its application that are expected to be added into rate base in December of any test year.

8.3.4 Necessity for the separation of certain accounts into subaccount categories and the requirement for additional studies with respect to these accounts

414. In its evidence, the RPG asserted that due to the radical increases in the structural capability to withstand extreme weather, margins for wear and tear, and surplus transfer capability, new steel towers constructed under ISO Rule 502.2 must be treated as a separate and distinct group for depreciation purposes and not be combined with ATCO Electric's existing steel towers account.[299]

415. The RPG stated that by placing these new assets (i.e., the ones constructed in compliance with ISO Rule 502.2) in a separate subaccount, the actuarial service life and net salvage data

[298] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 129, PDF pages 55-58.
[299] Account 455.1 (USA 354) – towers and fixtures – steel.

could be accumulated and used to independently determine applicable depreciation parameters as distinct from those for assets constructed prior to ISO Rule 502.2 taking effect.

416. When asked if any other transmission plant accounts would be similarly affected by the design specifications of ISO Rule 502.2, the RPG responded that Account 453 (USA 355) – transmission – poles and fixtures (wooden); Account 454 – transmission – overhead conductors poles (wooden poles); and Account 454.10 (USA 356) – transmission – overhead conductors towers (steel towers) would also be affected by these design specifications, but likely not to the same degree as Account 455.10 (USA 354) – transmission – towers and fixtures (steel).[300]

417. The RPG also recommended that a comprehensive and independent study be conducted to determine the probability of tower failures and that the results thereof be incorporated by ATCO Electric into a revised estimate of service lives in a compliance filing or, at the very latest, the next depreciation study.[301] In its argument, the RPG further recommended that ATCO Electric be directed to complete a net salvage study in a form similar to the study filed in the RPG's evidence.[302] The RPG stated with respect to these two studies that "both need to go really together."[303]

418. In rebuttal, Mr. Kennedy described an alternative to creating a sub-account to recognize differing life characteristics of the type asserted for assets constructed under ISO Rule 502.2, that being the implementation of a vintage group method, where all the benefits of subdividing the account are gained without the creation of a subaccount. Under the vintage group method, all investment from a given year forward would be subject to a differing average service life expectation. This would generally be the case with all assets constructed subsequent to the implementation of ISO Rule 502.2 in 2012.[304]

419. During oral questioning, Mr. Jansen stated with respect to creating a subaccount for Account 455.10 (USA 354) – towers and fixtures (steel) constructed under ISO Rule 502.2, that ATCO Electric was open to separating the assets into dedicated subaccounts and then, in a subsequent depreciation study, conducting a review to determine whether there need to be differences between the older and newer towers.[305] This view was reiterated in ATCO Electric's argument.

420. Gannett Fleming did not file or refer to any studies discussing the examination of, or support for, the proposed life characteristics of transmission towers constructed from steel. It instead relied on more traditional tools, including statistical and peer analysis and comments of operational staff. Mr. Kennedy advised that with respect to ISO Rule 502.2, Gannett Fleming's structural, electrical and geotechnical professional engineering staff had read and reviewed the ISO standard and provided an opinion as to the reasonability of a 70-year service life.[306]

421. Mr. Kennedy stated that after his preliminary review of costs of retirement data, he requested ATCO Electric to engage their operation and engineering staff to examine this aspect

[300] Exhibit 20272-X0811, RPG-AUC-2016FEB01-002, PDF pages 5-6.
[301] Exhibit 20272-X0789, RPG evidence, PDF pages 84-85, and 95.
[302] Exhibit 20272-X1297, RPG argument, paragraph 396, PDF page 131.
[303] Transcript, Volume 13, pages 2375-2376.
[304] Exhibit 20272-X1121, Gannett Fleming rebuttal evidence, PDF pages 32-33.
[305] Transcript, Volume 11, pages 2067-2068.
[306] Transcript, Volume 11, pages 1909-1910.

and provide further detail. Mr. Kennedy's request resulted in ATCO Electric's preparation of a net salvage study[307] that was used as support for Mr. Kennedy's net salvage percentage proposal.

422. During questioning from Commission counsel, RPG witness, Mr. Trevor Cline, expressed dissatisfaction with the net salvage study prepared by ATCO Electric stating that "…what ATCO has undertaken in their study and concept is what we have in mind. But as Mr. Levson said, I think it must be done to a greater level of sophistication."[308] The RPG indicated a preference for a study consistent with an example they provided which had been prepared in the 1980s for TransAlta Utilities.[309]

Commission findings

423. The Commission agrees with the RPG that given the nature of the assets constructed to comply with ISO Rule 502.2, it would be beneficial to initiate steps to collect data that will support life-curve and net salvage parameters in future depreciation studies.

424. On that basis, ATCO Electric is directed to identify and create a subaccount category for any USA account that now includes, and in the future will include, assets constructed to comply with ISO Rule 502.2, including any assets or capital projects constructed before the ISO rule came into effect, where projects have been constructed under the assumption that ISO Rule 502.2 would be adopted. ATCO Electric is directed to comply with this finding at the time of its next depreciation study.

425. The Commission finds it unnecessary to direct ATCO Electric to prepare or commission the tower failure or net salvage studies recommended by the RPG. Rather, in addition to the historical data that currently exists for the accounts affected by ISO Rule 502.2, the Commission will continue to rely on the tools available to it for examining life-curve and net salvage parameters, including any statistical analysis derived from the individual subaccount categories created under the above direction (such as the retirement rate analysis and traditional net salvage study), relevant peer analysis, professional depreciation and engineering expertise, manufacturers' information and the observations and comments of utility personnel. These will be considered and evaluated as evidence potentially supporting the impending service life and net salvage recommendations attached to the newly created subaccounts. Should ATCO Electric wish to supplement its recommendations through engineering reports or third-party studies in future applications, the Commission would consider such information in evidence.

8.4 Average service life and Iowa survivor curve adjustments

426. Depreciation accounting systematically and rationally allocates the difference between the original cost and the net salvage value of depreciable property over an estimated average service life. The average service life resulting from an Iowa curve estimate is the principal determining factor of the depreciation rate which, when applied to the cost of the utility asset, determines depreciation expense.

427. When examining a depreciation study, average service life and Iowa curve (life-curve) recommendations are reviewed by parties to consider whether the resultant depreciation rates and expense are supported.

[307] Exhibit 20272-X0413, AET-CCA-2015JUL10-004(v)(iii), Attachment 1, PDF page 394.
[308] Transcript, Volume 13, page 2379.
[309] Transcript, Volume 13, page 2377.

428. The life-curve estimates relied on by ATCO Electric were based on the proposals of its depreciation consultant, Mr. Kennedy. Mr. Kennedy used judgement in considering a number of factors including: the statistical analysis of actuarial data; current policies and outlook as determined through conversations and interviews with management and operational personnel; knowledge and review of upcoming capital projects; Mr. Kennedy's knowledge of current practices in the electric transmission industry; and the service lives and net salvage estimates used by other electric transmission companies.[310]

429. Further, a summary of the general weighting of any factors considered was provided along with industry information respecting life-curve statistics of nine comparative utilities, three of which are regulated by the Commission.

8.4.1 Account 451 (USA 350.1) – transmission facilities – land rights

430. Account 451 (USA 350.1) – transmission – land rights, comprises an average $84 million, or approximately 2.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 73-R4 for this account, which reflected a modification to the average service life and retirement dispersion from the currently approved 75-R3 for this account.

431. Mr. Kennedy recommended the change to the life-curve combination based on the conclusion that the currently approved Iowa curve was no longer a good fit to the actual retirement experience.[311]

432. Peer statistics for four utilities indicated average service lives between 20 and 60 years.[312]

433. During the course of this proceeding Mr. Kennedy confirmed that $0.3 million in "known and upcoming retirement activity" was incorporated into the retirement rate analysis which informed the determination of estimated service life and depreciation rate calculations.

434. Mr. Pous recommended an estimated service life-curve of 100-R4 for this account based on his view that land rights do not retire and, being perpetual in nature, should remain in service for at least one complete life cycle of the investment located upon it. Mr. Pous stated that the land rights associated with transmission corridors will in almost all cases be used and useful for a period in excess of 100 years.[313]

435. In argument, the RPG expressed its agreement with Mr. Pous' recommendations.[314]

Commission findings

436. Given that the Commission elsewhere in this Decision has denied the use of forecasts for the purposes of establishing depreciation parameters in a depreciation study, the Commission will explore other evidence and forms of analysis in its consideration of parties' proposed life-curve parameters.

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310 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 27 and 32.
311 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 34.
312 Exhibit 20272-X0585, AltaLink, ENMAX, BC Hydro and NALCOR, WP-824, PDF page 827.
313 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 27-28.
314 Exhibit 20272-X1297, RPG argument, PDF pages 117-118.

437. In examining the graphical representations prepared by Mr. Pous for this account (without the $0.3 million forecast retirements), the Commission observes that the 100-R4 life-curve proposed by Mr. Pous appears to provide the best visual fit to the data.[315]

438. However, while the Commission agrees with the logic used by Mr. Pous to have Account 451 (USA 350.1) – transmission – land rights assume a 100-R4 life-curve, it is also cognizant that ATCO Electric has no historical data illustrating complete life cycles reaching 100 years of service for any of its transmission assets that would otherwise support adoption of Mr. Pous' recommendation of a 100-year average service life (which is associated with a maximum service life of 135 years).

439. In light of the foregoing, the Commission finds there is no compelling basis on which to change the approved 75-R3 life-curve parameters for this account.

440. ATCO Electric is directed to maintain its approved 75-R3 life-curve for Account 451 (USA 350.1) – transmission – land rights in its compliance filing to this decision.

8.4.2 Account 453 (USA 355) – transmission facilities – poles and fixtures (wooden)

441. Account 453 (USA 355) – transmission – poles and fixtures (wooden), comprises an average $632 million, or approximately 10.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 60-R2 for this account, which reflected a modification to the average service life and retirement dispersion from the currently approved 55-R3 for this account.

442. Mr. Kennedy recommended a change in the life-curve combination based on his conclusion that the currently approved Iowa curve was no longer a good fit to the actual retirement experience. Based on a series of visual curve fits, Mr. Kennedy recommended a change in the life-curve parameters to 60-R2.[316]

443. Peer statistics for six utilities indicated average service lives between 37 and 55 years.[317]

444. During the course of this proceeding, Mr. Kennedy confirmed that $13 million in "known and upcoming retirement activity" was incorporated into the retirement rate analysis, which informed the determination of estimated service life and also depreciation rate calculations.

445. Mr. Pous recommended an estimated service life-curve of 63-R2 for this account. This was based on what he considered to be a "superior interpretation of the actuarial results"[318] and on operational factors identified by ATCO Electric operational personnel. Mr. Pous also considered industry expectations of longer service lives due to enhanced maintenance practices such as chemical treatment for the wooden poles.

446. Mr. Pous stated that the forecast retirement activity included by Mr. Kennedy has artificially lowered or "depressed" the observed life table (graphical representation) used in the visual curve fitting process.

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315 Exhibit 20272-X0925, CCA-AUC-2016FEB01-006(b).
316 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 35.
317 Exhibit 20272-X0585, AltaLink, Manitoba Hydro, ENMAX, BC Hydro, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
318 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 30.

447. In argument, the RPG expressed its agreement with Mr. Pous' 63-R2 life-curve recommendation and concluded that because it resulted in a lower residual measure it was a better mathematical fit through the meaningful portion of the observed life table.[319]

Commission findings

448. Given that the Commission elsewhere in this Decision has denied the use of forecasts for the purposes of establishing depreciation parameters in a depreciation study, the Commission will explore other evidence and forms of analysis in its consideration of parties' proposed life-curve parameters.

449. In examining the graphical representations prepared by Mr. Pous for this account (without the $13 million forecast retirements), the Commission observes that the approved 55-R3 life-curve appears to provide the best visual fit to the data until approximately age 45.[320]

450. However, taking into consideration the comments of ATCO Electric operational personnel that a 60-year life per wooden pole is reasonable and representative of the observed service life,[321] the Commission will accept this evidence as the basis for approving a life-curve combination of 60-R2 for Account 453 (USA 355) – transmission – poles and fixtures (wooden), as filed.

451. The Commission also observes that approximately 40 per cent of the assets in this account remain in service at age 67 years, which further supports a lengthening of the average service life for this account from the approved 55 years.

452. The Commission understands that this finding results in a life-curve parameter that is slightly longer than those of the peer utilities, but considers this to be a reasonable outcome in the circumstances.

8.4.3 Account 454 (USA 356) – transmission facilities – overhead conductors poles (wooden poles)

453. Account 454 (USA 356) – transmission – overhead conductors poles (wooden poles), comprises an average $243 million, or approximately 4.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 65-R3 for this account, which reflected a modification to the average service life and retirement dispersion from the currently approved 60-R4 for this account.

454. Mr. Kennedy recommended the change to the life-curve combination based primarily on the retirement rate experience, the comments received from ATCO Electric operational staff and the experience of Gannett Fleming.[322]

455. Peer statistics for six utilities indicated average service lives between 47 and 65 years.[323]

[319] Exhibit 20272-X1297, RPG argument, PDF page 118.
[320] Exhibit 20272-X0923, CCA-AUC-2016FEB01-007(b).
[321] Exhibit 20272-X0585, WP-817, PDF page 820.
[322] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 36-37.
[323] Exhibit 20272-X0585, AltaLink, Manitoba Hydro, ENMAX, BC Hydro, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.

456. During the course of this proceeding Mr. Kennedy confirmed that $4 million in "known and upcoming retirement activity" was incorporated into the retirement rate analysis which informed the determination of estimated service life and also depreciation rate calculations.

457. Mr. Pous stated that the proposed increase in service life was a step in the right direction but was still inadequate. He recommended an estimated service life-curve of 70-R2.5 for this account based on his view that the actuarial analysis provided information supporting a longer service life.[324]

458. In argument, the RPG expressed its agreement with Mr. Pous' recommendations and stated that Mr. Kennedy appears to arbitrarily make decisions based on a predetermined desired result.[325]

Commission findings

459. Given that the Commission elsewhere in this decision, has denied the use of forecasts for the purposes of establishing depreciation parameters in a depreciation study, the Commission will explore other evidence and forms of analysis in its consideration of parties' proposed life-curve parameters.

460. In examining the graphical representations prepared by Mr. Pous for this account (without the $4 million forecast retirements), the Commission observes that the approved 60-R4 life-curve appears to provide the best visual fit to the data until approximately age 50.[326]

461. Appreciating that Mr. Kennedy stated his average service life recommendation of 65 years was based primarily on the comments received from ATCO Electric operations personnel[327] the Commission will accept this evidence as the basis for approving a life-curve combination of 65-R3 for Account 454 (USA 356) – transmission – overhead conductors poles (wooden poles), as filed.

462. The Commission also observes that approximately 80 per cent of the assets in this account remain in service at age 67 years. In its view, this provides further support for a lengthening of the average service life for this account to 65 years from the approved 60 years.

463. The Commission notes that an average service life of 65 years is at the upper range of the peer utility statistics.

8.4.4 Account 454.1 (USA 356) – transmission facilities – overhead conductors towers (steel towers)

464. Account 454.1 (USA 356) – transmission – overhead conductors towers (steel), comprises an average $404 million, or approximately 7.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 65-R4 for this account, which reflected a modification to the average service life from the 60-R4 curve currently approved and reflected a lack of retirement transactions since the last depreciation study.

[324] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 35 and 38.
[325] Exhibit 20272-X1297, RPG argument, PDF pages 118-119.
[326] Exhibit 20272-X0921, CCA-AUC-2016FEB01-008(b).
[327] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 36-37.

465. Mr. Kennedy recommended the change to the life-curve combination based primarily on the comments received from ATCO Electric operational staff and the experience of Gannett Fleming.[328]

466. Peer statistics for six utilities indicated average service lives between 47 and 65 years.[329]

467. Mr. Pous recommended an estimated service life-curve of 70-R2.5 for this account based on recommendations and rationales similar to those underpinning the life-curve provided for Account 454 (USA 356) – transmission – overhead conductors poles (wooden poles), which indicated that actuarial analysis supported a longer service life.[330]

468. In argument, the RPG expressed its agreement with Mr. Pous' recommendations stating that there was a lack of any contrary evidence supporting a lower life-curve combination.[331]

Commission findings

469. In examining the graphical representations prepared by Mr. Pous for this account, the Commission finds that ATCO Electric's proposed 65-R4 life-curve combination appears to provide the best fit to the data,[332] and is within the range of the peer utility comparisons provided by Mr. Kennedy.

470. Considering that Mr. Kennedy stated that his average service life recommendation of 65 years was based primarily on the comments received from ATCO Electric operations personnel,[333] the Commission accepts this evidence as the basis for approving a 65-R4 life-curve combination of Account 454.1 (USA 356) – transmission – overhead conductors towers (steel), as filed.

471. The Commission also finds it reasonable that the average service life for overhead conductors for steel towers should be similar to that of overhead conductors for wooden poles.

8.4.5 Account 455.1 (USA 354) – transmission facilities - towers and fixtures (steel)

472. Account 455.1 (USA 354) – transmission – towers and fixtures (steel), comprises an average $1,857 million, or approximately 31.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 65-R4 for this account, which reflected a modification to the average service life from the currently approved 50-R4 life curve for this account.

473. Mr. Kennedy's recommendation to change the life-curve combination was primarily based on comments received from ATCO Electric operational staff and the experience of Gannett Fleming. Operational staff indicated that steel towers would have a life at least as long as wooden poles, for which a service life of 65 years was proposed.[334]

328 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 36-37.
329 Exhibit 20272-X0585, AltaLink, Manitoba Hydro, ENMAX, BC Hydro, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
330 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 39.
331 Exhibit 20272-X1297, RPG argument, PDF page 119.
332 Exhibit 20272-X0920, CCA-AUC-2016FEB01-009.
333 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 36-37.
334 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 38-39.

474. Addressing the recommendation for an independent review of ISO Rule 502.2 and its applicability to plant constructed under its design specifications, Mr. Kennedy stated that Gannett Fleming's structural, electrical and engineering staff had reviewed the rule and provided a verbal opinion that without a detailed engineering-based assessment of a variety of factors it was not possible to determine any type of significant life extension.[335]

475. Peer statistics for six utilities indicated average service lives between 45 and 85 years.[336]

476. Mr. Pous recommended an estimated service life-curve of 70-R4 for this account based on his interpretation of the actuarial results from the existing data, as well as the more robust design and capability of the new plant added to this account.[337]

477. Mr. Kennedy argued that Mr. Pous had not provided specific detail or analysis to support his recommended increase of some 40.0 per cent to the currently approved average service life for this account.[338]

478. Mr. Dan Levson clarified that while the RPG evidence stated that a significant extension in the average service life of the steel towers account is reasonable due to the radical increases in the structural capability to withstand extreme weather, margins for wear and tear, and surplus transfer capability, it was not advocating for a particular average service life.[339]

479. In argument, the RPG recommended that the Commission approve the life-curve combination of 70-R4 proposed by Mr. Pous. The RPG stated that considering Mr. Kennedy had placed a weighting of "high" on the use of peer comparisons, it followed that the average service life should be 70 due to average service lives in Canada being as high as 85 years for the same account. The RPG also noted that an average service life of 70 years is the most common recommendation made by Gannett Fleming for investment in similar accounts.[340]

Commission findings

480. The Commission agrees that a lengthening of the average service life for Account 455.1 (USA 354) – transmission – towers and fixtures (steel) is required in order to recognize the longer life characteristics observed in the actuarial analysis.

481. In examining the graphical representations prepared by Mr. Pous for this account, the Commission finds that ATCO Electric's proposed life-curve of 65-R4 appears to provide the best fit to the data,[341] and that this life-curve is within the middle range of the peer utility comparisons provided by Mr. Kennedy.

482. Considering that Mr. Kennedy stated that his average service life recommendation of 65 years was primarily based on comments received from ATCO Electric operations personnel,[342]

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335 Exhibit 20272-X0492, Appendix Response to CCA-DepMotion-AET-CCA-2015JUL10-004(a)(vi), PDF pages 13-15.
336 Exhibit 20272-X0585, AltaLink, Manitoba Hydro, ENMAX, BC Hydro, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
337 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 41.
338 Exhibit 20272-X1298, ATCO Electric argument, paragraph 132, PDF page 61.
339 Transcript, Volume 14, pages 2372-2374.
340 Exhibit 20272-X1297, RPG argument, paragraph 363, PDF page 120.
341 Exhibit 20272-X0919, CCA-AUC-2016FEB01-010.
342 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 38-39.

the Commission also accepts this as additional support for approving a life-curve combination of 65-R4 for Account 455.1 (USA 354) – transmission – towers and fixtures (steel), as filed.

8.4.6 Account 457 (USA 353) – transmission facilities – substation equipment – AC

483. Account 457 (USA 353) – transmission – substation equipment – AC, comprises an average $1,840 million, or approximately 30.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 51-R2 for this account, which reflected a modification to the average service life and dispersion from the currently approved 53-R3 life curve for this account.

484. Mr. Kennedy recommended the change to the life-curve combination based on a visual fit of the proposed 51-R2 life-curve, comments received from ATCO Electric operational staff and consideration of the peer utility statistics. Additionally, Mr. Kennedy considered the life shortening aspects of some newer technology being placed into service in this account.[343]

485. Peer statistics for six utilities indicated average service lives between 30 and 50 years.[344]

486. During the course of this proceeding, it was stated that $18 million in "known and upcoming retirement activity" had been incorporated into the retirement rate analysis which informed the determination of estimated service life and also depreciation rate calculations. However, during the hearing, it was established that this forecast information was, in fact, not included in the retirement rate analysis.[345]

487. Mr. Pous stated that ATCO Electric's specific data (whether estimated or actual on a corrected basis) implied that a longer average service life was warranted. In support of this statement, Mr. Pous provided a plotted graph of the actuarial data for this account comprising only historical data and compared it to Mr. Kennedy's proposed life-curve parameter of 51-R2 and Mr. Pous' proposed life-curve parameter of 56-R2. Mr. Pous concluded that the 56-R2 life-curve combination is a better fit through the meaningful portions of the curve.[346]

488. In argument, the RPG expressed its agreement with Mr. Pous' recommendations stating that his life-curve was a better mathematical fit through the meaningful portions of the observed life table.[347]

Commission findings

489. The Commission has reviewed the comments provided to Mr. Kennedy by ATCO Electric operational personnel and finds that they do not support a conclusion that the relevant life estimates should be shortened. Instead, the Commission finds the ATCO Electric staff comments, which included a consideration of various offsetting factors, to suggest that there should either be no change or a slight extension to average service life:

> Building newer expansive substations, they are larger with substantial upgrade to the systems than those of the past. Older buildings are becoming an issue and being replaced

343 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 40-41.
344 Exhibit 20272-X0585, AltaLink, Manitoba Hydro, ENMAX, Yukon Electric Corporation Limited, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
345 Exhibit 20272-X1246, Undertaking 79, Transcript, Volume 11, page 2031.
346 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 44-46.
347 Exhibit 20272-X1297, RPG argument, PDF pages 120-121.

> with newer ones. Ninety percent of the time a new substation will be built on the pre-existing site or next to it. The substations will be able to handle more capacity and large fault currents with a beefier system. In addition, the substations will become more synchronous and capacitors reactors for better voltage control. AE is replacing a 72KV [kilovolt] substation that is oil based to a vacuum breaker technology. There is a phase-out program for PCB breakers as needed, with about 144 oil breakers still in the system.
>
> Life of substations are extending due to an increased amount of life extension maintenance however, this is offset by a lighter build quality and an increase in loading of the system. Of note, with the advent of SF6 technology in the breakers at the substations and evolution the expectations should require less maintenance.[348]

490. It is not clear to the Commission how the average service life of "newer expansive substations" that are "larger with substantial upgrade to the systems" and able to "handle more capacity and large fault currents with a beefier system" was determined to be offset and further diminished by a "lighter build quality" and "increase in loading."

491. In addition, in the graphical representations prepared by Mr. Pous for this account, the Commission finds that ATCO Electric's approved life-curve of 53-R3 appears to provide the best fit to the data.[349]

492. For these reasons, the Commission considers there to be insufficient support for a change to the approved life-curve combination of 53-R3 for this account. ATCO Electric is directed to incorporate depreciation parameters of 53-R3 for Account 457 (USA 353) – transmission – substation equipment – AC in its compliance filing to this decision.

8.4.7 Account 457.1 (USA 353) – transmission facilities – HVDC conductors towers

493. Mr. Kennedy recommended that starting in 2014, assets related to the new HVDC system be collected in a separate substation subaccount so that future depreciation studies can analyze the services lives of the assets comprising the HVDC system separately. Mr. Kennedy stated that this account currently includes a wide range of assets including shorter life digital control systems to longer lived high voltage transformers.[350] The Commission understands that the proposed new subaccount, Account 457.1 (USA 353) – transmission – HVDC conductors towers, would comprise an average $323 million, or approximately 5.0 per cent of ATCO Electric's forecast plant during the test period.

494. Mr. Kennedy did not provide a written discussion of his recommended parameters for this new account. However, from the Commission's review of the depreciation study and GTA schedules, it is apparent that a 53-R3 life-curve[351] was proposed. These parameters are consistent with those currently approved for Account 457 (USA 353) – transmission – substation equipment – AC.

495. There were no peer statistics provided for this account.

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348 Exhibit 20272-X0585, WPs-814-815, PDF pages 817-818.
349 Exhibit 20272-X0917, CCA-AUC-2016FEB01-011(b).
350 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 40.
351 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 62, 66 and 70 and Exhibit 20272-X1101, Schedule 6-3, line no. 74.

496. Mr. Pous did not provide a written discussion of his recommendations for this account, however, it was apparent that his proposal of a 56-R2 life-curve for Account 457.1 (USA 353) – transmission – HVDC conductors towers, which was provided within a summary of the CCA's recommended mass property life adjustments, was consistent with his recommendations for Account 457.[352]

497. In argument, the RPG expressed its agreement with Mr. Pous' recommendations.[353]

Commission findings

498. The Commission agrees that in the absence of actuarial data or any other substantive evidence for the life-curve recommendations, the adoption of the approved life-curve parameters of Account 457 (USA 353) – transmission – substation equipment – AC as a surrogate for the life-curve parameters for Account 457.1 (USA 353) – transmission – HVDC conductors towers, is the most reasonable course of action.

499. The Commission approves a 53-R3 life-curve for Account 457.1 (USA 353) – transmission – HVDC conductors towers, as filed.

8.4.8 Account 482 (USA 390) – General plant – structures and improvements

500. Account 482 (USA 390) – general plant – structures and improvements, comprises an average $92 million, or approximately 2.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric proposed a life-curve combination of 40-R2.5 for this account, which reflected a modification to the average service life and dispersion from the currently approved 55-R3 for this account.

501. The currently approved life-curve of 55-R3 includes a number of buildings related to ATCO Electric's distribution operations that are no longer part of this transmission-only account.

502. Mr. Kennedy recommended the change to the life-curve combination based on the results of the 40-R2.5 life-curve retirement pattern, which included a significant level of retirements throughout the life of the account. His proposals were supported by comments received from ATCO Electric operational staff as being representative of the future expectations for this account.[354]

503. Peer statistics for eight utilities indicated average service lives between 40 and 100 years.[355]

504. Mr. Pous did not agree with the 15-year reduction in service life for this account stating that it was unrealistically low. Mr. Pous argued that, logically, a blending of the various lives of the assets associated with this account should result in a life far exceeding the 40-year average proposed by Mr. Kennedy.[356]

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[352] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 18.
[353] Exhibit 20272-X1297, RPG argument, PDF pages 120-121.
[354] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 43.
[355] Exhibit 20272-X0585, AltaLink, Manitoba Hydro, Fortis Alberta, ENMAX, Yukon Electric Corporation Limited, Northland Utilities (Yellowknife) Limited, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
[356] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 49-51.

505. In argument, the RPG expressed its agreement with Mr. Pous' recommendations.[357]

Commission findings

506. The Commission considers it reasonable that the life characteristics for this account may have changed given that distribution-related assets no longer form part of the relevant historical data. However, the Commission is not prepared to effect a 15-year reduction in average service life without further evidence that the shortened life characteristics for the remaining building and structures assets are of a long-term nature.

507. The Commission is similarly not persuaded that ATCO Electric's general structures and improvement assets should be at the lowest range of the peer utility statistics.

508. Mr. Kennedy placed a low weighting on the 40-R2.5 life-curve "fit to the DATA" and a high weighting on "peer comparison" in his weighting of factors analysis. In this case, the Commission finds that the results of Mr. Kennedy's weighting of factors analysis are inexplicably at odds with the evidence and peer statistics.[358] Consequently, the Commission is unable to assign more than minimum weight to Mr. Kennedy's recommendations regarding this account.

509. The Commission finds Mr. Pous' recommendation to be reasonable given the new composition of this account. ATCO Electric is directed to incorporate a life-curve of 50-R2.5 for Account 482 (USA 390) – general plant – structures and improvements, in its compliance filing to this decision.

8.4.9 Account 489 (USA 399.2) – general plant – leaseholds

510. Mr. Kennedy proposed to establish Account 489 (USA 399.1) – general plant – leaseholds, as a depreciation study account subject to a square Iowa curve (SQ curve) amortization methodology.

511. An average service life of eight years was recommended based on the development of an investment-weighted average service life of existing (i.e., embedded) leaseholds. It was proposed that this be reviewed at each subsequent depreciation study.

512. Previously, this account was amortized on the basis of tracking and amortizing individual leaseholds. The change to an SQ methodology would result in the use of a methodology consistent with other types of general plant accounts. There would also be benefits in terms of a reduced administrative burden associated with tracking the leases.

513. The change to an amortization methodology would increase the depreciation expense for leasehold improvements over the test period by approximately $2.4 million when compared to using the existing methodology. Mr. Kennedy and Mr. Jansen confirmed the increase was an expected short term result of the change.[359]

514. Neither Mr. Pous nor the RPG raised issues specific to the proposed SQ methodology or average service life recommendation for this account, nor did they recommend alternative parameters in their depreciation evidence.

[357] Exhibit 20272-X1297, RPG argument, PDF page 121.
[358] Exhibit 20272-X0585, ATCO Electric – weighting of factors, WP-826, PDF page 829.
[359] Transcript, Volume 11, pages 2034-2039.

Commission findings

515. The Commission finds the recommendation to be reasonable given the administrative benefits inherent in applying an SQ curve methodology in this case and the fact that neither it nor interveners have otherwise identified any concerns with this methodology.

516. The Commission is satisfied with the proposed methodology used to determine the average service life for this group of assets and approves the use of a 8-SQ life-curve for Account 489 (USA 399.1) – general plant – leaseholds.

8.4.10 General plant – software: Account 496.1 (USA n/a) – general plant – software – major; Account 496.2 (USA n/a) – general plant – software – minor; Account 496.3 (USA n/a) – general plant – software – desktop

517. Mr. Kennedy proposed to establish ATCO Electric's three software subaccount categories as depreciation study accounts subject to a square Iowa curve (SQ curve) amortization methodology similar to that adopted in the case of the leasehold accounts. The witnesses explained that adoption of this methodology also presented an opportunity to lessen the administrative burden otherwise associated with this account. During the hearing, Mr. Kennedy and Mr. Jansen discussed the difficulties associated with determining when a software package should be retired. This process was described as a challenging exercise given the nature of the assets and their propensity to be upgraded through multiple releases and iterations.[360]

518. These three software subaccounts comprise an average $61 million, or approximately 1.0 per cent of ATCO Electric's forecast plant during the test period.

519. The general plant – computer software subaccount numbers and names and proposed life-curves are set out in the following table:

Table 24. Summary of proposed software subaccount categories and life-curve parameters

AET Account	Description	AET proposed life-curve	CCA proposed life-curve
496.1	Software – major	7-SQ	10-SQ
496.2	Software – minor	5-SQ	7-SQ
496.3	Software - desktop	3-SQ	n/a

Source: Exhibit 20272-X1101, GTA Schedules, schedule 6-3 and Exhibit 20272-X0780 and evidence of Jack Pous, Tables, PDF pages 18 and 60.

520. The "major" software category consists of programs such as Oracle whereas the "minor" category included Records Management and GIS. The "desktop" category consisted entirely of the Windows 7 Upgrade. Mr. Kennedy described the recommended average service lives of seven years (software – major category), five years (software – minor category) and three years (desktop category) as being the result of historical experience, the opinion of IT professionals and industry trends.[361]

521. The change to an SQ curve methodology in combination with the proposed service life recommendations would increase the depreciation expense for these three accounts by

[360] Transcript, Volume 11, pages 2041-2044.
[361] Transcript, Volume 11, pages 2047-2048.

$9.6 million during the test period. This increase was considered to be short term in nature and the result of "more of a cleansing exercise to assure the datum" over the test period.[362]

522. Mr. Pous was not concerned with the adoption of the amortization-based approach for ATCO Electric's software accounts,[363] but objected to the recommended average service lives for the major and minor categories. He instead proposed that the Commission approve a 10-SQ curve and 7-SQ curve, respectively, for the two accounts.

523. Mr. Pous argued that Mr. Kennedy did not provide any study or analysis of the recommended service lives and pointed to an IR response provided by ATCO Electric stating that the company had plant in service that had already exceeded the proposed amortization periods recommended by himself and Mr. Kennedy.[364]

524. In argument, the RPG expressed its agreement with Mr. Pous' recommendations, concluding that the longer amortization periods do not deny ATCO Electric the recovery of its investment, but better align the recovery with the expected useful service life of the asset, thus reducing intergenerational inequity issues.[365]

525. ATCO Electric summited that the recommended changes were fair and deal with the amortization of software subaccount categories in a pragmatic manner.[366]

Commission findings

526. The Commission accepts Mr. Kennedy's proposal to establish ATCO Electric's three software subaccount categories[367] as depreciation study accounts using an SQ curve methodology as a being a reasonable way to reduce the administrative burden associated with tracking each software program and associated updates on an individual basis.

527. The Commission accepts the 3-SQ life-curve for Account 496.3 – general plant – software – desktop. However, the Commission finds that Mr. Kennedy's proposed service lives for ATCO Electric's major and minor software subaccount categories are both unsupported and unreasonably short.

528. The Commission accepts Mr. Pous' observation that ATCO Electric is still using some versions of its software programs[368] as opposed to having retired the assets as being no longer used and required to be used. In the absence of actual retirement experience under ATCO Electric's existing amortization methodology for its software accounts, the Commission is unable to determine the reliability of Mr. Kennedy's proposed service lives. Instead, the Commission considers it reasonable to take a more conservative approach and accepts the service lives recommended by Mr. Pous.

529. ATCO Electric is directed to incorporate a 10-SQ life-curve for Account 496.1 – general plant – software – major and a 7-SQ life-curve for Account 496.2 – general plant – software –

362 Transcript, Volume 11, pages 2057.
363 Transcript, Volume 12, page 2186.
364 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 52 and 54.
365 Exhibit 20272-X1297, RPG argument, PDF pages 121-122.
366 Exhibit 20272-X1298, ATCO Electric argument, paragraph 150, PDF page 68.
367 General plant – software: Account 496.1 (USA n/a) – general plant – software – major; Account 496.2 (USA n/a) – general plant – software – minor; Account 496.3 (USA n/a) – general plant – software – desktop.
368 Exhibit 20272-X0453, AET-CCA-2015JUL10-008.

minor and to incorporate these findings in its compliance filing to this decision. The 3-SQ life-curve for Account 496.3 – general plant – software – desktop is approved.

8.5 Net salvage percentage adjustments

530. Net salvage amounts equate to the salvage value of property retired less the costs of retirement. When costs of retirement exceed the salvage values of the property retired, net salvage is a negative value or percentage, to be collected through depreciation expense over the life of the asset. The estimate of net salvage is recovered as a component of the depreciation rate for each property account over the life of the asset so that when an asset is retired, the costs necessary to remove it from service will already have been collected and made available to the utility through its depreciation practices.

531. During the course of a depreciation study, a net salvage analysis is undertaken to ensure that the negative net salvage being collected continues to be indicative of future retirement cost expectations. This section examines the proposed adjustments to, and supporting rationale for, the net salvage percentages for each account.

532. The estimates of net salvage were based primarily on Mr. Kennedy's professional judgment, in part on historical data as described below, and in part on a comparison to peer companies. ATCO Electric's recommended net salvage percentages relied on a traditional approach to net salvage analysis that also considered historical data on actual retirement activity for the years 1970 through 2013 for most accounts.

533. Net salvage percentage statistics provided in a traditional net salvage analysis include the year by year net salvage percentage, the overall net salvage percentage for the time period examined, three-year moving average percentages and the most recent five-year average percentage.[369]

534. Competitive markets and regulated markets are not differentiated within common depreciation definitions. Competitive markets set prices in a completely different manner than regulated markets and there is a loose connection between expected earnings and the prices that are ultimately charged.

535. For regulated utilities, the Commission must set a fair and reasonable return. This return is based upon each utility's investment in rate base. This rate base is reduced by no cost capital within the utility which is directly related to the depreciation expense (including net salvage) and deferred taxes.

536. When regulated utilities accelerate the collection of taxes or depreciation then current customers pay a greater share of those costs. When these current costs become excessive versus future costs the Commission must ensure that the resulting tariff is still just and reasonable and not unduly preferential, or arbitrarily or unjustly discriminatory.[370]

537. The tariff that is set in a regulated context includes the depreciation expense and net salvage component, however it must also include the return on rate base. This return decreases over time as the rate base declines due to the accumulation of depreciation expense. This phenomenon is accelerated when high negative net salvage rates are adopted. Future customers

[369] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 33.
[370] *Electric Utilities Act*, Section 121(2).

therefore pay even less for the annual consumption of an asset than do current customers. This differential in intergenerational impacts is mitigated to some extent as long as a utility's rate base is continuously growing. However, in circumstances involving discrete large additions to rate base, current customers pay an increased share of costs. This impact is effectively amplified by the addition of increased negative net salvage values as this will require the collection of even greater amounts from current customers relative to future customers.

538. Regulated firms in Alberta collect their investment in utility assets by way of depreciation expense using the straight line method. Historically, net salvage has been a relatively minor component in these calculations. A -10.0 per cent net salvage means that 10.0 per cent of historical cost will be collected over time so that the utility has that amount on hand when the asset is retired from utility service and salvaged. However, it does not necessarily mean that these costs must be allocated equally each and every year at the same rate to each customer.

539. Now that net salvage rates are being requested at significantly higher levels, the Commission must ensure that all parties fully appreciate the potential effects of such changes on the justness and reasonableness of rates. Alternatives to collecting negative net salvage amounts on other than a "straight line" basis were not considered in this proceeding.

8.5.1 Account 453 (USA 355) – transmission facilities – poles and fixtures (wooden)

540. Account 453 (USA 355) – transmission – poles and fixtures (wooden), comprises an average $632 million, or approximately 10.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric recommended a change in net salvage from -90.0 per cent to -175.0 per cent for this account based on the traditional net salvage study provided and the inclusion of forecasts of $13 million in retirements and $16 million in costs of retirement.

541. From 1970 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, has ranged from 98.0 per cent to -818.0 per cent, with an overall historical net salvage of -139.0 per cent. Three-year moving averages for this same period ranged from 88.0 per cent to -447.0 per cent and the most recent five-year average net salvage figure was -129.0 per cent.[371]

542. Excluding the forecast retirements and costs of retirement from the net salvage study leaves total retirement experience at $8 million and net salvage experience at $14 million for the 1970 to 2013 period and results in a 2013 net salvage percentage of -102.0, an overall net salvage percentage of -161.0 and a most recent five-year average net salvage of -148.0 per cent.

543. Peer statistics for three utilities showed net salvage percentages ranging from -35.0 per cent to -52.0 per cent.[372]

544. Mr. Kennedy stated that in ATCO Electric's 2009 depreciation study, despite indications of net salvage percentages in the order of -150.0 to -200.0 per cent, a "graduated and moderated approach was warranted until more years of increased highly negative net salvage requirements were witnessed."[373] Mr. Kennedy considered that the recent statistical results in the current

[371] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 109-111.
[372] Exhibit 20272-X0585, AltaLink, ENMAX, Northland Utilities (NWT) Limited WP-825, PDF page 828.
[373] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 36.

depreciation study were evidence that a significant increase in net salvage percentage from -90.0 per cent to -175.0 per cent was required.

545. Mr. Pous argued that based on Mr. Kennedy's peer group results, a net salvage percentage of -40.0 to -50.0 per cent was warranted. Mr. Pous viewed his recommendation to retain the -90.0 per cent net salvage value as "a very conservative estimate in favour of the Company" which he provided despite his concern that ATCO Electric had not supported the retention of its currently approved -90.0 net salvage per cent. Mr. Pous' recommendation was made in conjunction with a recommendation that the Commission "direct AET to fully investigate, explain and substantiate why reliance on its cost codes and other accounting practices results in the recording of cost of removal levels that are appreciably different from the identifiable industry."[374]

546. In argument, the RPG expressed its agreement with Mr. Pous' recommendations including the request for further explanations from ATCO Electric of its costs of removal.[375]

Commission findings

547. Given that the Commission elsewhere in this decision has denied the use of forecasts for the purposes of establishing depreciation parameters in a depreciation study, the Commission will explore other evidence and forms of analysis in its consideration of parties' proposed net salvage parameters.

548. The Commission has concerns with respect to the magnitude of the increase in net salvage percentage proposed by ATCO Electric. The current net salvage of -90.0 per cent already far exceeds the upper end of the range for peer utilities.

549. Further, the data relied on by Mr. Kennedy consists of actual retirements and costs of retirement experience in the amounts of $8 million and $14 million, respectively, for the years 1970 to 2013. The Commission has concerns that this limited experience does not provide sufficient support to conclude that a net salvage of -175.0 per cent is representative of future net salvage expectations for assets with a total cost of $632 million.

550. For these reasons, the Commission directs ATCO Electric to maintain its currently approved net salvage percentage of -90.0 in its compliance filing to this decision for Account 453 (USA 355) – transmission – poles and fixtures (wooden).

551. At the same time, the Commission wishes to obtain a better understanding of why ATCO Electric's costs of retirement for this account appear to significantly exceed that of industry peers and considers it would be in the public interest and of considerable benefit to the Commission for ATCO Electric to include a detailed explanation for this in its next depreciation study. ATCO Electric is directed to provide the noted explanation in its next depreciation study.

8.5.2 Account 454.1 (USA 356) – transmission facilities – overhead conductors towers (steel towers)

552. Account 454.1 (USA 356) – transmission – overhead conductors towers (steel), comprises an average $404 million, or approximately 7.0 per cent of ATCO Electric's forecast

[374] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 64- 65.
[375] Exhibit 20272-X1297, RPG argument, PDF page 124.

plant during the test period. ATCO Electric recommended a change in net salvage from -20.0 per cent to -50.0 per cent for this account based on the traditional net salvage study provided.

553. From 1997 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, ranged from 0.0 per cent to -437.0 per cent, with an overall historical net salvage of -173.0 per cent. Three-year moving averages for this same period ranged from 36.0 per cent to -564.0 per cent, while the most recent five-year average net salvage was -267.0 per cent.[376]

554. Peer statistics for three utilities showed net salvage percentages ranging from -20.0 per cent to -50.0 per cent.[377]

555. Mr. Kennedy stated that while the limited retirement experience of $0.2 million and net salvage experience of $0.3 million for this account did not support the overall -173.0 per cent net salvage on a prospective basis, the current figure of -20.0 per cent was too low. Comments from ATCO Electric operational staff indicated that the costs to retire conductor on steel towers would be similar to that of wooden poles. ATCO Electric argued that Mr. Kennedy's proposed -50.0 per cent for this account would therefore match the approved net salvage rate for Account 454 (USA 356) – overhead conductors poles (wooden).[378]

556. Neither Mr. Pous nor the RPG raised issues specific to the proposed net salvage recommendation for this account nor did they recommend alternative parameters in their depreciation evidence.

Commission findings

557. The Commission considers ATCO Electric's proposal that, in the absence of actuarial data or any other substantive evidence for a net salvage percentage recommendation, the adoption of a parameter of a similar-type account is a reasonable course of action. In the case of Account 454.1 (USA 356) – transmission – overhead conductors towers (steel towers), the currently approved -50.0 per cent net salvage for Account 454 (USA 356) – transmission – overhead conductors poles (wooden) could be used.

558. However, the Commission observes that for Account 454.1 (USA 356) – transmission – overhead conductors towers (steel towers), there is 17 years of actuarial data in the net salvage study from which to draw on, notwithstanding that the data is scattered between retirements, costs of retirement and gross salvage, and does not provide a useful trend. The Commission agrees with Mr. Kennedy that it would be premature to adopt an overall net salvage of -173.0 per cent notwithstanding such actuarial data as exists.

559. The Commission agrees that the current net salvage percentage of -20.0 per cent is too low. The Commission considers that, in the near term, establishing a net salvage estimate of -30.0 per cent is reasonable and within the range of peer utility statistics. ATCO Electric will have the opportunity in its next depreciation study to incorporate further actuarial data that may result in an updated net salvage estimate.

[376] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 115.
[377] Exhibit 20272-X0585, AltaLink, ENMAX, Northland Utilities (NWT) Limited WP-825, PDF page 828.
[378] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 38.

560. The Commission directs ATCO Electric to incorporate a net salvage of -30.0 per cent for Account 454.1 (USA 356) – transmission – overhead conductors towers (steel towers), in its compliance filing to this decision.

8.5.3 Account 455.1 (USA 354) – transmission facilities – towers and fixtures (steel)

561. Account 455.1 (USA 354) – transmission – towers and fixtures (steel), comprises an average $1,857 million, or approximately 31.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric recommended a change in net salvage from -25.0 per cent to -200.0 per cent for this account based on the traditional net salvage study provided.

562. From 1995 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, has ranged from 0.0 per cent to -896.0 per cent, with an overall historical net salvage of -914.0 per cent. Three-year moving averages for this same period ranged from 0.0 per cent to -522.0 per cent, while the most recent five-year average net salvage was in excess of -1,000.0 per cent.[379]

563. Peer statistics for three utilities showed net salvage percentages ranging from -5.0 per cent to -35.0 per cent.[380]

564. Mr. Kennedy stated that notwithstanding the limited retirement experience of $0.4 million and net salvage experience of $3.7 million which reflects only a small percentage of the total plant installed, the current figure of -25.0 per cent was too low.[381]

565. Mr. Kennedy incorporated comments from ATCO Electric operational staff in his review of their engineering-based analysis of the activities and costs associated with the removal of steel transmission towers. The study concluded that the costs related to the removal of steel towers exceed those associated with the removal of wooden poles. After considering ATCO Electric's comments, Mr. Kennedy recommended that the net salvage for Account 455.1 (USA 354) – transmission – towers and fixtures (steel) be set at -200.0 per cent instead of at the -175.0 per cent net salvage rate proposed for Account 453 (USA 355) – poles and fixtures (wooden), to reflect the projected higher removal costs.[382]

566. Mr. Pous stated that ATCO Electric had failed to provide evidence supporting any level of net salvage percentage for this account. He nonetheless recommended that the current -25.0 net salvage percentage be doubled to -50.0 per cent, which he described as "a very conservative estimate in favor of the company." Mr. Pous explained that his recommendation considered the more robust nature of the ISO Rule 502.2 constructed towers and was made in conjunction with a recommendation that the Commission "direct AET to develop and present on a timely basis a meaningful and completely documented and supported study of realistic net salvage values for this account in the next depreciation study."[383]

567. The RPG argued that ATCO Electric's attempt to justify the largest requested change in its depreciation expense was inadequate, warranted much closer scrutiny and constituted a significant concern for ratepayers. The RPG stated that ATCO Electric had initially chosen to

379 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 115.
380 Exhibit 20272-X0585, AltaLink, ENMAX, Northland Utilities (NWT) Limited WP-825, PDF page 828.
381 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 39.
382 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 41.
383 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 66 and 69.

withhold the net salvage study used to determine its steel tower net salvage percentage recommendation. The proposed change to a -200.0 per cent net salvage parameter represented an incremental $4.03 billion in capital recovery over the life of steel towers and would bring the total cost of these facilities to $6.9 billion before any consideration of return. The RPG was critical of the fact that the engineering report underpinning the net salvage study was only provided during the IR phase of the proceeding, was "insubstantial" and further, "could not be spoken to by the members of [ATCO Electric's] depreciation panel during the oral hearing." The RPG stated that "these practices are inconsistent with the onus that [ATCO Electric] has to justify its depreciation rates."[384] [385]

Commission findings

568. The Commission has concerns with respect to the magnitude of the increase in net salvage percentage proposed by ATCO Electric. The current net salvage parameter of -25.0 per cent is at the upper end of the range for peer utilities.

569. Further, the data being relied on by Mr. Kennedy consists of limited actual retirements and costs of retirement experience in the amounts of $0.4 million and $3.7 million, respectively, for the years 1995-2013. The Commission considers that this is inadequate experience and does not provide sufficient support for the conclusion that a net salvage of -200.0 per cent is representative of future net salvage costs for an account of this magnitude.

570. The Commission finds there is insufficient actual retirement and cost of retirement data to support the very large change in net salvage percentage proposed by Mr. Kennedy. The Commission is of the view that, until further actuarial data can be accumulated to substantiate an estimate closer to that recommended by Mr. Kennedy, maintaining the current net salvage percentage of -25.0 is reasonable. ATCO Electric will have the opportunity in its next depreciation study to incorporate further actuarial data in support of a revised net salvage estimate.

571. The Commission directs ATCO Electric to incorporate a net salvage of -25.0 per cent for Account 455.1 (USA 354) – transmission – towers and fixtures (steel) in its compliance filing to this decision.

572. This finding is within the range of peer utility statistics.

8.5.4 Account 457 (USA 353) – transmission facilities – substation equipment – AC

573. Account 457 (USA 353) – transmission – substation equipment – AC, comprises an average $1,840 million, or approximately 30.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric recommended a change in net salvage from -10.0 per cent to -40.0 per cent for this account based on the traditional net salvage study provided and forecasts of $18 million in retirements and $23 million in costs of retirement.

574. From 1970 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, has ranged from 125.0 per cent to -715.0 per cent, with an overall historical net salvage of -68.0 per cent. Three-year moving averages for this same period ranged from 208.0

[384] Exhibit 20272-X1297, RPG argument, paragraph 343, PDF page 113.
[385] Exhibit 20272-X1297, RPG argument, paragraph 370, PDF page 122.

per cent to -110.0 per cent, while the most recent five-year average net salvage was -101.0 per cent.[386]

575. Excluding the forecast retirements and costs of retirement from the net salvage study leaves total retirement experience at $25 million and net salvage experience at $6 million for the 1970 to 2013 period and results in a 2013 net salvage percentage of -28.0, an overall net salvage percentage of -25.0 and a most recent five-year average of -46.0 per cent.

576. Peer statistics for four utilities showed net salvage percentages ranging from -10.0 per cent to -35.0 per cent.[387]

577. Mr. Kennedy stated that while the limited retirement experience of $43 million and net salvage experience of $29 million (including the forecast retirements and costs of retirement) is based on only a small percentage of the total plant installed, the current net salvage percentage of -10.0 has been insufficient over the past 40-year period. Comments from ATCO Electric operational staff indicated that the costs to retire substation assets will continue to increase in future years.[388]

578. Mr. Pous opposed Mr. Kennedy's proposal to increase the negative net salvage percentage to -40.0. According to Mr. Pous, given the poor understanding of the composition of this account, too much reliance was being placed on the historical database and the results of the traditional net salvage study. Mr. Pous also claimed that the data from which Mr. Kennedy drew his results was very poor and stated that Mr. Kennedy's proposal to increase the net salvage percentage for this account by a factor of four was excessive. Mr. Pous recommended a -15.0 net salvage percentage.[389]

579. In argument, the RPG expressed its agreement with Mr. Pous' recommendations.[390]

Commission findings

580. The Commission finds that the use of forecast retirements and forecast removal costs significantly influenced the results of the traditional net salvage study. Given that the Commission elsewhere in this decision has denied the use of forecasts for the purposes of establishing depreciation parameters in a depreciation study, the Commission will explore other evidence and forms of analysis in its consideration of parties' proposed net salvage parameters.

581. The Commission finds that when forecast retirements and forecast costs of retirement are excluded, the results of the net salvage study do not support Mr. Kennedy's proposals.

582. The Commission agrees with Mr. Kennedy that there is limited retirement and cost of retirement experience available for this account. However, given the consistency of the actual historical data relating to retirements, costs of retirement and gross salvage activity, there is sufficient stability in the observed trend of increasing net salvage costs to permit the Commission to make a determination with respect to the reasonableness of the proposed net salvage percentages.

386 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 119-120.
387 Exhibit 20272-X0585, AltaLink, ENMAX, Yukon Electric Corporation Limited and Northland Utilities (NWT) Limited WP-825, PDF page 828.
388 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 41.
389 Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF pages 70-71.
390 Exhibit 20272-X1297, RPG argument, paragraph 375, PDF page 1173.

583. The Commission accepts the net salvage percentage of -15.0 proposed by Mr. Pous and observes that this figure is within the range of peer utility net salvage percentages. The Commission directs ATCO Electric to implement a net salvage of -15.0 per cent in its compliance filing to this decision for Account 457 (USA 353) – transmission – substation equipment – AC.

8.5.5 Account 457.1 (USA 353) – transmission facilities – HVDC conductors towers

584. Mr. Kennedy recommended that the net salvage percentage proposed for the AC substation assets also be used for Account 457.1 (USA 353) – transmission – HVDC conductors towers until such time as sufficient historical information is accumulated to allow for an independent net salvage study.

585. Mr. Pous agreed with Mr. Kennedy's proposal to base the net salvage percentage for the HVDC substation assets on that of the AC substation assets, but submitted that they should both be set at -15.0 per cent and not -40.0 per cent as recommended by Mr. Kennedy.

Commission findings

586. The Commission agrees that in the absence of actuarial data or any other substantive evidence for the life-curve recommendations, the adoption of the net salvage parameters of Account 457 (USA 353) – transmission – substation equipment – AC for this account, is a reasonable course of action.

587. Until sufficient actuarial data supports an independent determination of service life characteristics, ATCO Electric is directed to incorporate a net salvage of -15.0 per cent for Account 457.1 (USA 353) – transmission – HVDC conductors towers in its compliance filing to this decision.

588. A -15.0 net salvage percentage is consistent with that approved for Account 457 (USA 353) – transmission – substation equipment – AC.

8.5.6 McNeill converter station accounts[391]

589. Mr. Kennedy did not provide separate written testimony in support of his recommended net salvage parameters for any of the three McNeill converter station accounts identified above. However, within the depreciation study and GTA schedules, it was apparent that he was proposing increases in negative net salvage parameters for these three accounts.

590. The McNeill converter station subaccount numbers and names and proposed net salvage percentages are set out in the following table:

[391] Account 453.02 (USA 355) – McNeill convertor station – poles and fixtures; Account 454.02 (USA 356) – McNeill convertor station – overhead conductors poles; and Account 457.02 (USA 353) – McNeill convertor station – substation equipment.

Table 25. Summary of proposed McNeill converter station subaccount categories and net salvage percentages

AET account and (USA account)	Description of McNeill converter station subaccount categories	AET approved net salvage (%)	AET proposed net salvage (%)	CCA proposed net salvage (%)
453.02 (USA 355)	Poles and fixtures	-2.0	-50.0	-90.0
454.02 (USA 356)	Overhead conductors poles	-2.0	-50.0	-50.0
457.02 (USA 353)	Substation equipment	-2.0	-10.0	-15.0

Source: Exhibit 20272-X1101, GTA Schedules, schedule 6-3 and Exhibit 20272-X0780 and Evidence of Jack Pous, Tables, PDF pages 18 and 60 and Q&A PDF page 77.

591. For Account 453.02 – poles and fixtures, there was no basis provided for the increase in proposed net salvage percentage from -2.0 to -50.0.

592. For Account 454.02 – overhead conductors poles, Mr. Kennedy recommended that net salvage be set at -50.0 per cent consistent with the approved net salvage parameters for Account 454 (USA 356) – overhead conductors poles (wooden poles).[392] [393]

593. In response to an IR,[394] Mr. Kennedy stated that although his net salvage recommendations for substation equipment were based on Gannett Fleming's experience with HVDC stations in other jurisdictions they exhibited similar net salvage characteristics to those of ATCO Electric's AC substation assets.

594. For Account 457.02 – substation equipment, Mr. Kennedy stated that, notwithstanding Gannet Fleming's experience with other jurisdictions that supported a general increase to the net salvage parameter for this account, he was reluctant to propose a significant increase at this time. Mr. Kennedy recommended that a net salvage percentage not exceeding -10.0 be implemented until retirement costs associated with HVDC station assets become better known.

595. Mr. Pous agreed that for the conductors account (Account 454.02), net salvage should be the same -50.0 per cent as the related transmission conductor account (Account 454).

596. Mr. Pous also proposed that Account 453.02 – poles and fixtures (wooden) and Account 457.02 – substation equipment be assigned the same net salvage percentages of -90.0 and -15.0 as those applicable to related transmission accounts – Account 453 and Account 457, respectively.[395]

597. In argument, the RPG expressed its agreement with the net salvage percentages Mr. Pous recommended for ATCO Electric's two McNeill converter station accounts.[396]

Commission findings

598. The Commission agrees that in the absence of actuarial data or any other substantive evidence for the life-curve recommendations, the adoption of the net salvage parameters of the

[392] The Commission observes that the reference provided in the IR response was to Account 454.10, but identified overhead conductors poles (wooden) (which is Account 454). Account 454.10 is overhead conductors towers (steel towers).
[393] Exhibit 20272-X0437, AET-AUC-2015JUN08-125, PDF pages 43-44.
[394] Exhibit 20272-X0437, AET-AUC-2015JUN08-125, PDF pages 43-44.
[395] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 77.
[396] Exhibit 20272-X1297, RPG argument, paragraph 377, PDF page 125.

transmission accounts to which the McNeill converter station assets are most closely related is a reasonable course of action. This finding aligns with the recommendations of Mr. Pous.

599. Until there is sufficient actuarial data to support an independent determination of net salvage characteristics, ATCO Electric is directed to incorporate, for its McNeill convertor station assets, net salvage in the amount of -90.0 per cent for Account 453.02 (USA 355) – poles and fixtures; -50.0 per cent for Account 454.02 (USA 356) – overhead conductors poles; and -15.0 per cent for Account 457.02 (USA 356) – substation equipment.

8.5.7 Account 482 (USA 390) – general plant – structures and improvements

600. Account 482 (USA 390) – general plant – structures and improvements, comprises an average $92 million, or approximately 2.0 per cent of ATCO Electric's forecast plant during the test period. ATCO Electric recommended no change in net salvage from the -5.0 per cent approved for this account.

601. From 1970 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, has ranged from 160.0 per cent to -632.0 per cent, with an overall historical net salvage of -11.0 per cent. Three-year moving averages for this same period ranged from 549.0 per cent to -723.0 per cent, while the most recent five-year average net salvage was 74.0 per cent.[397]

602. Peer statistics for three utilities reflected net salvage of 10.0 per cent in all instances.[398]

603. The net salvage study showed large proceeds from dispositions within this account. Mr. Kennedy, however, did not expect sales such as these to re-occur in the future.

604. As a result, Mr. Kennedy proposed retaining the currently approved -5.0 per cent net salvage parameter.

605. Mr. Pous challenged Mr. Kennedy's proposal to maintain the approved -5.0 per cent net salvage parameter on the grounds that it did not reflect the type of assets in this account. Mr. Pous instead recommended a 15.0 per cent net salvage based on his understanding and interpretation of ATCO Electric's investment and historical data as it relates to the real estate market.

606. Mr. Pous stated that sales of offices, warehouses and similar-type structures often generate significant levels of positive net salvage well after their initial construction, as was observed for ATCO Electric's three most recent reported facility sales.[399]

Commission findings

607. The results of ATCO Electric's net salvage study show erratic annual retirements, and significant variability in costs of retirement and gross salvage transactions, all of which may reflect timing differences with respect to the recording of accounting entries. This would also explain the fluctuations in annual net salvage percentages which can lead to difficulties in establishing year-over-year trends.

[397] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 122-123.
[398] Exhibit 20272-X0585, AltaLink, ENMAX and Yukon Electric Corporation Limited, WP-825, PDF page 828.
[399] Exhibit 20272-X0780, CCA evidence of J. Pous – Depreciation, PDF page 76.

608. The Commission is of the view that the potential to recover positive net salvage in the long term outweighs the likelihood of incurring negative net salvage for ATCO Electric's general plant – structures and improvement assets. While the Commission believes there may be good reason to increase the net salvage percentage to a positive value, it is not prepared to do so without statistical support from the net salvage study.

609. ATCO Electric's proposal to maintain its approved net salvage of -5.0 per cent for 482 (USA 390) – general plant – structures and improvements is approved as filed.

8.5.8 Account 486 (USA 353.1) – general plant – communications structures and equipment

610. Account 486 (USA 353.1) – general plant – communications structures and equipment, comprises an average $225 million, or approximately 4.0 per cent of ATCO Electric's forecast plant during the test period. Although ATCO Electric recommended a net salvage parameter of -15.0 per cent for this account, Mr. Kennedy provided no support for doing so in his depreciation study.

611. From 1970 to 2013, net salvage, as a percentage of the original cost of the assets retired in each year, has ranged from 105.0 per cent to -156.0 per cent, with an overall historical net salvage of -1.0 per cent. Three-year moving averages for this same period ranged from 79.0 per cent to -194.0 per cent, while the most recent five-year average net salvage was -41.0 per cent.[400]

612. Peer statistics for one utility showed a net salvage of 15.0 per cent.[401]

613. Neither Mr. Pous nor the RPG contested the net salvage recommendation with respect to this account, nor did they recommend alternative parameters in their depreciation evidence.

Commission findings

614. The Commission finds no compelling evidence within the net salvage study for the recommendations made by Mr. Kennedy. It also finds the proposed negative net salvage percentage to be inconsistent with that for the only available peer utility. Consequently, it denies ATCO Electric's request to implement a net salvage of -15.0 per cent for Account 486 (USA 353.1) – general plant – communications structures and equipment.

615. ATCO Electric is directed to use its approved net salvage of 0.0 per cent for Account 486 (USA 353.1) – general plant – communications structures and equipment in its compliance filing to this decision.

8.6 General plant – transportation equipment accounts[402]

616. In this section, the Commission will evaluate the recommended life-curve and net salvage parameters for Accounts 484.01 to 484.06 (USA 392.1 to 392.6) which comprise ATCO Electric's four existing general plant – transportation equipment subaccounts, and the proposal to establish two additional transportation equipment subaccount categories.

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400 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 122-123.
401 Exhibit 20272-X0585, AltaLink, WP-825, PDF page 828.
402 General plant – transportation equipment: Account 484.01 (USA 392.1) – category 1; Account 484.02 (USA 392.2) – category 2; Account 484.03 (USA 392.3) – category 3; Account 484.04 (USA 392.4) – category 4; Account 484.05 (USA 392.5) – category 5; Account 484.06 (USA 392.6) – category 6.

617. The currently approved and proposed transportation equipment subaccount numbers and names, and approved and proposed life-curve and net salvage parameters, are set out in the following table:

Table 26. Summary of currently approved and proposed transportation equipment subaccount categories and life-curve and net salvage parameters

AET account	USA account	Description	Approved Decision 2011-134 2008 parameters (2011-2014) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.
484.01	392.1	Transportation equipment - category 1	10-L1.5	10%	8-L1.5	10%
484.02	392.2	Transportation equipment - category 2	12-L1	10%	9-L2	10%
484.03	392.3	Transportation equipment - category 3	25-R3	20%	18-S0	5%
484.04	392.4	Transportation equipment - category 4	12-R2	20%	10-L3	15%
484.05	392.5	Transportation equipment - category 5 (new – associated with existing category 2)	n/a	n/a	4-S3	5%
484.06	392.6	Transportation equipment - category 6 (new – associated with existing category 3)	n/a	n/a	8-S3	5%

Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3.

618. Mr. Kennedy conducted retirement rate analysis, and included recommended life-curve combinations based on the visual best fit, in his depreciation study with respect to ATCO Electric's four existing transportation equipment subaccounts.[403] Current average service lives for the four existing subaccounts ranged from 10 to 25 years, while proposed average service lives ranged from eight to 18 years.[404] [405] Mr. Kennedy sought support for the reasonableness of his proposals in ATCO fleet management expectations with respect to service lives and the company's historical operational experience.

619. Peer statistics for nine utilities show average service lives of between three and 20 years for similar-type transportation equipment account categories.[406]

620. Mr. Kennedy proposed that two new subaccounts[407] be established within the overall transportation category that would be specifically assigned to travelling construction crews. Because this equipment would experience more mileage and usage than that found in other transportation equipment subaccount categories, Mr. Kennedy proposed significantly shorter service lives than those recommended for the existing asset categories. Mr. Kennedy did not provide retirement rate analysis for the two proposed account subcategories.

621. ATCO Electric's fleet management group used best estimates supported by recently gathered data and judgement in arriving at service life expectations. These were viewed as

403 General plant – transportation equipment: Account 484.01 (USA 392.1) – category 1; Account 484.02 (USA 392.2) – category 2; Account 484.03 (USA 392.3) – category 3; Account 484.04 (USA 392.4) – category 4.
404 Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF page 43.
405 Exhibit 20272-X0585, WPs-821-822, PDF pages 824-825.
406 Exhibit 20272-X0585, AltaLink, Manitoba Hydro, Fortis Alberta, ENMAX, BC Hydro, Yukon Electric Corporation Limited, Northland Utilities (Yellowknife) Limited, Northland Utilities (NWT) Limited and NALCOR, WP-824, PDF page 827.
407 General plant – transportation equipment: Account 484.05 (USA 392.5) – construction 1; Account 484.06 (USA 392.6) – construction 2.

reasonable by Mr. Kennedy given the conditions under which these transportation assets will be operated.

622. Mr. Kennedy conducted traditional net salvage studies for the four existing transportation equipment subaccounts and recommended decreases in the net salvage percentages for two of the subaccounts: Account 484.03 – category 3 (currently approved 20.0 per cent, proposed 5.0 per cent) and Account 484.04 – category 4 (currently approved 20.0 per cent, proposed 15.0 per cent).

623. Mr. Kennedy also proposed to implement new net salvage parameters for each of the two new subaccounts: Account 484.05 – category 5 (proposed 5.0 per cent) and Account 484.06 – category 6 (proposed 5.0 per cent) on the basis of the recommendations provided by the ATCO Electric Fleet Management group.

624. Neither Mr. Pous nor the RPG objected to the life-curve or net salvage percentage proposals of ATCO Electric or Mr. Kennedy for the six transportation equipment depreciation study accounts identified above, nor did they recommend alternative parameters in their depreciation evidence.

Commission findings

625. The Commission has examined the plotted original and smooth survivor curves for the four existing transportation equipment account categories and finds that, in all cases, the proposed life-curve parameters provide a good fit to the data and are within the range of the peer utility statistics. The proposed life-curve combinations for ATCO Electric's four existing transportation account categories are approved.

626. The Commission also accepts ATCO Electric's proposal to establish two new transportation equipment subaccounts for assets subject to more extreme operating conditions on the basis that the life characteristic of these two accounts are distinct from ATCO Electric's existing accounts: Account 484.05 (USA 392.5) – general plant – transportation equipment – category 5 and Account 484.06 (USA 392.6) – general plant – transportation equipment – category 6.

627. Despite approving the use of new subaccounts for this asset class, the Commission finds that the evidence tendered in support of the recommended life-curve and net salvage percentages for the these accounts is insufficient to justify their adoption.

628. The Commission observes that the calculated annual and accrued depreciation schedules provided for the two proposed accounts contain no information prior to 2013. Consequently, it considers it reasonable to assume that these two accounts are being established on a go-forward basis rather than on the basis of historical data for specifically identified assets subject to the extreme operating conditions identified by ATCO Electric.

629. The Commission considers that the operating conditions that assets in these two new accounts will be subject to, should result in shorter service lives but, as there was no retirement rate analysis provided for these two accounts, it directs ATCO Electric to apply life-curve

parameters consistent with those approved for the accounts with which the new accounts were previously associated.[408]

630. On this basis, the Commission directs ATCO Electric to incorporate a 9-L2 life-curve for Account 484.05 (USA 392.5) – general plant – transportation equipment – category 5; and a 18-SO life curve for Account 484.06 (USA 392.6) – general plant – transportation equipment – category 6 in its compliance filing to this decision.

631. ATCO Electric may apply to update these service lives in subsequent depreciation studies once actuarial data is accumulated, examined and can provide the required support for updated life-curve recommendations.

632. With respect to ATCO Electric's proposals to reduce net salvage percentages for two of its existing accounts, the results of the net salvage studies conducted for Account 484.03 – category 3 show the overall and five-year average net salvage percentages were 40.0 and 19.0 respectively, and for Account 484.04 – category 4 the overall and five-year average net salvage percentages were 10.0 and 18.0, respectively.[409]

633. The Commission finds that the results of the net salvage studies for these two accounts do not support the proposed reductions in net salvage percentages from those approved and directs ATCO Electric to maintain the approved net salvage percentages for Account 484.03 (USA 392.3) – category 3 in the amount of 20.0 per cent and Account 484.04 (USA 392.4) – category 4 in the amount of 20.0 per cent in its compliance filing to this decision.

634. Although the Commission agrees that the operating conditions for equipment in the two new transportation subaccounts should result in lower gross salvage, given the lack of a net salvage study, the Commission finds it both reasonable and necessary to direct ATCO Electric to apply net salvage percentages consistent with those approved for the accounts with which the new accounts were previously associated.[410]

635. On this basis, the Commission directs ATCO Electric to apply a 10.0 per cent net salvage for Account 484.05 (USA 392.5) – general plant – transportation equipment – category 5, and a 20.0 per cent net salvage for Account 484.06 (USA 392.6) – general plant – transportation equipment – category 6 in its compliance filing to this decision.

636. ATCO Electric may apply to update these gross salvage percentages in subsequent depreciation studies once actuarial data is accumulated, examined and can provide the required support for updated net salvage percentage recommendations.

637. The Commission acknowledges that ATCO Electric did not propose changes to the approved net salvage percentages for Account 484.01 (USA 392.) – general plant – transportation equipment – category (10.0 per cent), or Account 484.02 (USA 392.2) – general plant – transportation equipment – category 2 (10.0 per cent).

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[408] Proposed Account 484.05 – category 5 is associated with the existing Account 484.02 – category 2. Proposed Account 484.06 – category 6 is associated with the existing Account 484.03 – category 3.

[409] Exhibit 20272-X0621, AET-AUC-2015OCT16-016, Attachment 3, PDF pages 128-131.

[410] Proposed Account 484.05 – category 5 is associated with the existing Account 484.02 – category 2. Proposed Account 484.06 – category 6 is associated with the existing Account 484.03 – category 3.

8.7 General plant – tools and instruments accounts[411]

638. In this section, the Commission will evaluate the recommended life-curve parameters for ATCO Electric's existing Account 485.01 (USA 394) – general plant – tools and instruments – category 1 and the proposal to establish depreciation parameters for a new subaccount category. The new account, identified as Account 485.02 (USA 394.1) – general plant – tools and instruments – category 2, would consist of a subcategory of assets subject to harsher operating conditions and a shorter expected service life.

639. The currently approved and proposed tools and instruments subaccount numbers and names, and approved and proposed life-curve and net salvage parameters, are set out in the following table:

Table 27. Summary of currently approved and proposed tools and instruments subaccount categories and life-curve and net salvage parameters

AET account	USA account	Description	Approved Decision 2011-134 2008 parameters (2011-2014) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.
485.01	394	Tools and instruments - category 1	10-R2	n/a	8-SQ	n/a
485.02	394.1	Tools and instruments - category 2	n/a	n/a	4-SQ	n/a

Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3.

640. Mr. Kennedy provided no reasons to support his request to use an SQ curve for these two accounts or for the proposed decrease in average service life for Account 485.01 – general plant – tools and instruments – category 1 from 10 to eight years.

641. There were no peer statistics provided for these accounts.

Commission findings

642. The Commission is not opposed to the use of an SQ curve for accounts of this nature but finds that there is insufficient support for the proposed reduction in service life for Account 485.01 – general plant – tools and instruments – category 1 from 10 to eight years.

643. Further, the Commission is not persuaded of the need to establish a separate subaccount category, as proposed by ATCO Electric, for Account 485.02 – general plant – tools and instruments – category 2.

644. On that basis, the Commission directs ATCO Electric to incorporate life-curve parameters of 10-SQ for Account 485.01 – general plant – tools and instruments – category 1 and denies the establishment of Account 485.02 – general plant – tools and instruments – category 2.

645. ATCO Electric is directed to maintain a single account for all its tools and instrument type-assets and to incorporate a life-curve of 10-SQ for Account 485.01 – general plant – tools and instruments in its compliance filing to this decision.

[411] General plant – tools and instruments: Account 485.01 (USA 394) – category 1; Account 485.02 (USA 394.1) – category 2.

8.8 Generation plant accounts

646. ATCO Electric's generation accounts include investments associated with 13 remote diesel generation sites, one remote hydro site and several mobile generation units used to provide emergency back-up to the remote sites. This group of asset accounts comprises approximately 3.3 per cent of the total depreciation study accounts.

647. In the depreciation study, ATCO Electric maintained the unit lifespan approach to depreciation for the isolated generation assets which included hydro, diesel and gas turbine type-equipment.

648. The most significant change proposed by ATCO Electric was with respect to the Jasper Palisades isolated generation units. ATCO Electric's proposal to construct a transmission line into Jasper in the year 2018[412] will eliminate the need for these generation facilities. This, in turn, will result in a revised life span date, with 2018 becoming the year of final retirement, as well as updated costs of retirement estimates.

Table 28. Summary of approved and proposed 2015-2017 estimated depreciation parameters for generation assets

AET account	USA account	Description	Approved Decision 2011-134 2008 parameters (2011-2014) YFR/Int.Ret. Life-curve	N.S.	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-curve	N.S.
		Generation				
422	331	Hydro structures	2031	-115%	2045 / 75-R2	-115%
423	332	Hydro reservoirs, dams and waterways	2031	-115%	2045 / 100-R3	-115%
425	333	Hydro generators	2031	-77%	2031 / 75-R3	-77%
426	334	Hydro accessory electrical equipment	2031	-115%	2031 / 45-R3	-115%
427	335	Hydro miscellaneous plant equipment	2031	-115%	2031 / 25-R2	-115%
432	336	Gas turbine structures	2038	-5%	2017 / 50-R2	-125%
435	337	Gas turbine generators	2038	-5%	2017 / 35-R2	-1%
436	338	Gas turbine accessory electrical equipment	2038	-5%	2017 / 25-R1.5	0%
437	339	Gas turbine miscellaneous equipment	2038	-5%	2017 / 25-R1.5	0%
442	341	Internal combustion structures				
		Chipewyan Lake	2028	-6%	2028 / 50-R2	-6%
		Fawcet River	2030	-22%	2029 / 50-R2	-22%
		Fort Chipewyan	2042	-2%	2042 / 50-R2	-2%
		Garden River	2017	-6%	2017 / 50-R2	-6%
		Indian Cabins	2037	-3%	2037 / 50-R2	-3%
		Mobile Gen	2021	-5%	2022 / 50-R2	-5%
		Narrows Point	2031	-10%	2031 / 50-R2	-10%
		Palisades	2026	-5%	2017 / 50-R2	-125%
		Peace Point	2033	-9%	2033 / 50-R2	-9%
		Steen River Town	2032	-5%	2032 / 50-R2	-5%
		Touchwood	2031	-7%	2031 / 50-R2	-7%
444	342	Internal combustion fuel holders				

[412] Exhibit 20272-X1135, AET updates re common group placeholder and other items, Attachment 6, PDF 92 of 405.

AET account	USA account	Description	Approved Decision 2011-134 2008 parameters (2011-2014) YFR/Int.Ret. Life-curve	N.S.	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-curve	N.S.
		Generation				
		Chipewyan Lake	2028	-6%	2028 / 35-R3	-6%
		Fawcet River	2030	-22%	2029 / 35-R3	-22%
		Fort Chipewyan	2042	-2%	2042 / 35-R3	-2%
		Garden River	2017	-6%	2017 / 35-R3	-6%
		Indian Cabins	2037	-3%	2037 / 35-R3	-3%
		Narrows Point	2031	-10%	2031 / 35-R3	-10%
		Palisades	2026	-5%	2017 / 35-R3	0%
		Peace Point	2033	-9%	2033 / 35-R3	-9%
		Steen River Town	2032	-5%	2032 / 35-R3	-5%
		Touchwood	2031	-7%	2031 / 35-R3	-7%
445	343	Internal combustion generators				
		Chipewyan Lake	2028	-6%	2028 / 25-R3	-6%
		Fawcet River	2030	-22%	2029 / 25-R3	-22%
		Foggy Mountain	2033	-9%	2033 / 25-R3	-9%
		Fort Chipewyan	2042	-2%	2042 / 25-R3	-2%
		Garden River	2017	-6%	2017 / 25-R3	-6%
		Indian Cabins	2037	-3%	2037 / 25-R3	-3%
		Mobile Gen	2021	-5%	2022 / 25-R3	-5%
		Narrows Point	2031	-10%	2031 / 25-R3	-10%
		Palisades	2026	-5%	2017 / 25-R3	-1%
		Peace Point	2033	-9%	2033 / 25-R3	-9%
		Steen River Town	2032	-5%	2032 / 25-R3	-5%
		Touchwood	2031	-7%	2031 / 25-R3	-7%
446	345	Internal combustion accessory electrical equipment				
		Chipewyan Lake	2028	-6%	2028 / 35-R2	-6%
		Fort Chipewyan	2042	-2%	2042 / 35-R2	-2%
		Garden River	2017	-6%	2017 / 35-R2	-6%
		Indian Cabins	2037	-3%	2037 / 35-R2	-3%
		Narrows Point	2031	-10%	2031 / 35-R2	-10%
		Palisades	2026	-5%	2017 / 35-R2	0%
		Peace Point	2033	-9%	2033 / 35-R2	-9%
		Steen River Town	2032	-5%	2032 / 35-R2	-5%
		Touchwood	2031	-7%	2031 / 35-R2	-7%
447	346	Internal combustion miscellaneous electrical equipment				
		Fawcet River	2016	-22%	2029 / 40-R3	-22%
		Fort Chipewyan	2042	-2%	2042 / 40-R3	-2%
		Garden River	2017	-6%	2017 / 40-R3	-6%
		Indian Cabins	2037	-3%	2037 / 40-R3	-3%
		Narrows Point	2031	-10%	2031 / 40-R3	-10%
		Palisades	2026	-5%	2017 / 40-R3	0%
		Peace Point	2033	-9%	2033 / 40-R3	-9%
		Steen River Town	2032	-5%	2032 / 40-R3	-5%
		Touchwood	2031	-7%	2031 / 40-R3	-7%

Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3.

649. The discussion which follows is based on grouping ATCO Electric's generation plant into the following categories: hydro, Jasper Palisades and internal combustion.

8.8.1 Generation – hydro

650. ATCO Electric's hydro generation plant consists of five asset accounts: structures; reservoirs, dams and waterways; generators; accessory electrical equipment; and miscellaneous plant equipment.[413]

651. Year of final retirement estimates were updated for two of the asset categories: Account 422 (USA 331) – generation – hydro structures and Account 423 (USA 332) – generation – hydro reservoirs, dams and waterways. The approved estimate of retirement for these accounts was updated from the year 2031 to a revised estimated retirement in the year 2045.

652. Gannett Fleming explained that due to ongoing capital maintenance projects on the Astoria Hydro generation site, the life of these assets will be extended to 2045.[414]

653. For the other three accounts in this category, the year of final retirement remained the same as approved. The net salvage percentages also remained the same as approved for all five accounts.

Commission findings

654. The Commission agrees that the extension of the service life of the assets due to the ongoing capital maintenance programs should be recognized and accepts the revised year of final retirement of 2045 for ATCO Electric's hydro generation plant.

8.8.2 Generation – Jasper Palisades

655. ATCO Electric's Jasper Palisades[415] generation plant consists of two general categories: gas turbine and internal combustion. Within the gas turbine category there are four asset accounts: structures; generators; accessory electrical equipment; and miscellaneous equipment.[416] The internal combustion category has five asset accounts: structures; fuel holders; generators; accessory electrical equipment; and miscellaneous electrical equipment.[417]

656. As noted earlier, ATCO Electric's proposal to construct a transmission line into Jasper in the year 2018 will eliminate the need for the Jasper Palisades generation facilities. Therefore, a revised life span date of 2018 has been used as the year of final retirement for all Jasper Palisades plant accounts. Additionally, cost of retirement estimates were updated, the most

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413 Generation – hydro: Account 422 (USA 331) – structures; Account 423 (USA 332) – reservoirs, dams and waterways; Account 425 (USA 333) – generators; Account 426 (USA 334) – accessory electrical equipment, and; Account 427 (USA 339) – miscellaneous plant equipment.

414 Exhibit 20272-X0437, AET-AUC-2015JUN08-123, PDF pages 32-35.

415 The Commission observes that Gannett Fleming has referred to these generation assets as the Jasper Pallisades or the Pallisades.

416 Jasper Palisades – Generation – gas turbine: Account 432 (USA 336) – structures; Account 435 (USA 337) – generations; Account 436 (USA 338) – accessory electrical equipment, and; Account 437 (USA 339) - miscellaneous equipment.

417 Jasper Palisades – Generation - internal combustion: Account 442 (USA 341) – structures, Account 444 (USA 342) – fuel holders, Account 445 (USA 343) – generators; Account 446 (USA 345) – accessory electrical equipment, and; Account 447 (USA 346) – miscellaneous electrical equipment.

significant being revised estimates from the approved -5.0 per cent to a proposed -125.0 per cent for each of the gas turbine structures and internal combustion structures accounts. The year of final retirement and net salvage percentages for each of the nine asset accounts can be found in Table 23 above.

657. The increase in cost of retirement estimates to -125.0 per cent was based on revised retirement procedures that did not previously contemplate the removal of the concrete slabs or the dismantling and complete removal of the generation assets.[418] Further, as the proposal to provide service (PPS) for the transmission line interconnection advanced over the course of this proceeding, ATCO Electric was better able to understand Park Canada's project and environmental requirements.

658. During the hearing, ATCO Electric provided updated schedules showing the total accumulated life and net salvage depreciation balances forecast to be collected at the end of December 2017 (which was ATCO Electric's as-filed proposed year of final retirement) for the Jasper Palisades assets. The amount collected for the life portion was forecast to be $31.4 million of the total $41.5 million original historical cost of the assets. The amount collected for the net negative salvage portion was forecast to be $6.0 million of the total $8.6 million in anticipated net negative salvage.[419] [420]

659. Consequently, by December 2017, of the total estimated life and net negative salvage of $50.1 million,[421] approximately $37.4 million[422] will have been recovered through depreciation expense, leaving approximately $12.7 million to be recovered in the year 2018.

Commission findings

660. The Commission accepts ATCO Electric's revised year of final retirement of 2018 and net negative salvage estimates for Jasper Palisades generation assets as being related to the energization of the Jasper transmission interconnection thereby eliminating the need for the Jasper Palisades isolated generation plant.

661. However, as part of ATCO Electric's compliance filing, the Commission requires confirmation that ATCO Electric's calculated accumulated depreciation balances related to life and net salvage as of December 2017 are correct in that approximately $12.7 million in life and net negative salvage remains to be recovered in the year 2018 and beyond. ATCO Electric is directed to provide the requested confirmation and explain why the unrecovered balance is so large. ATCO Electric is also directed to describe the proposed method and period of recovery of the $12.7 million.

662. The Commission, as part of ATCO Electric's compliance filing, also directs that the year of final retirement of 2018 be reflected in the utility's GTA schedules along with any revisions required as a result of the direction in the paragraph above.

[418] Exhibit 20272-X0437, AET-AUC-2015JUN08-123, PDF pages 32-35.
[419] Exhibit 20272-X1135, AET updates re common group placeholder and other items, Attachment 6, PDF page 92.
[420] Exhibit 20272-X1275, Undertaking 83 updating the revised year of final retirement and net salvage estimate.
[421] Calculated as $41.5 million plus $8.6 million.
[422] Calculated as $31.4 million plus $6.0 million.

8.8.3 Generation – internal combustion

663. The balance of ATCO Electric's generation plant is related to five categories of internal combustion assets at various isolated generation sites in northern Alberta.[423] The internal combustion account categories are: structures; fuel holder; generators; accessory electrical equipment; and miscellaneous electrical equipment.[424] There were no recommended changes for the vast majority of year of final retirement and net salvage percentage accounts.

664. ATCO Electric proposed to make changes to the year of final retirement for its internal combustion assets at the Mobile Generation location (from the approved 2021 to the year 2022) and the Fawcet River location (from the approved 2030 to the year 2029).

665. The only net salvage parameter change requested for the internal combustion assets was with respect to Fawcet River's miscellaneous electrical equipment. When asked about an apparent decrease in net salvage from an approved -122.0 per cent to a requested -22.0 per cent, ATCO Electric responded that the request for a -22.0 per cent net salvage figure "was an error and should remain at the previously approved -122%."[425] ATCO Electric stated that the correction would be made in the O&U filing.

Commission findings

666. The Commission accepts ATCO Electric's revised year of final retirement of 2022 for the structure and generation assets at the utility's Mobile Generation site. The Commission also accepts ATCO Electric's revised year of final retirement of 2029 for the Fawcet River structures, fuel holders, generators and miscellaneous electrical equipment generation assets. These two changes are nominal in nature and are approved.

667. With respect to the Fawcet River net salvage percentage, the Commission observes that since the time of ATCO Electric's IR response on July 31, 2015, there were several iterations of depreciation studies and/or GTA schedules including the O&U filing on October 2, 2015. In no instance of these updates did ATCO Electric make the identified correction. In fact, the correction made was to change the approved net salvage from -122.0 per cent to -22.0 per cent, which leads the Commission to believe that the IR response should have pointed to an error in the *approved* negative net salvage percentage and not an error in the *proposed* negative net salvage percentage.

668. For this reason, the Commission directs ATCO Electric to confirm the currently approved negative net salvage percentage of the Fawcet River Account 447 (USA 346) - miscellaneous electrical equipment is -22.0 per cent and that no change has been requested for this account with respect to negative net salvage for the 2015-2017 test years.

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[423] Chipewyan Lake, Fawcet River, Fort Chipewyan, Garden River, Indian Cabins, Mobile Generation, Narrows Point, Peace Point, Steen River Town and Touchwood.

[424] Generation – internal combustion: Account 442 (USA 341) – structures; Account 444 (USA 342) – fuel holder; Account 445 (USA 343) – generators; Account 446 (USA 345) – accessory electrical equipment, and; Account 447 (USA 346) – miscellaneous electrical equipment.

[425] Exhibit 20272-X0437, AET-AUC-2015JUN08-123, PDF page 34-35.

8.9 Remaining depreciation study accounts

8.9.1 Accounts for which changes were proposed

669. ATCO Electric proposed changes to the currently approved service life and/or Iowa curve parameters for the following accounts:

(a) Account 483 (USA 391) – general plant – office furniture and equipment (currently approved 15-R3, proposed 15-SQ).

(b) Account 483.2 (USA 391.1) –general plant – computer equipment and accessories (currently approved 5-S0.5, proposed 5-SQ).

670. Intervening parties made no comments or alternative proposals with respect to the life-curve recommendations for these two accounts.

Commission findings

671. The Commission accepts the proposed change to an SQ dispersion curve for Account 483 (USA 391) – general plant – office furniture and equipment, and Account 483.2 (USA 391.1) – general plant – computer equipment and accessories, as reasonable given the nature of these accounts. The life-curve parameters for these two accounts are approved.

8.9.2 Accounts for which no changes were proposed

672. ATCO Electric did not propose changes to approved service life or Iowa curve parameters for the following accounts:

(a) Account 451.02 (USA 350.1) – McNeill converter station – land rights (currently approved and proposed 2035 / 45-R4).

(b) Account 453.02 (USA 355) – McNeill converter station – poles and fixtures (currently approved and proposed 2035 / 45-R3).

(c) Account 454.02 (USA 356) – McNeill converter station – overhead conductors poles (currently approved and proposed 2035 / 45-R3).

(d) Account 457.02 (USA 353) – McNeill converter station – substation equipment (currently approved and proposed 2035 / 45-R2.5).

(e) Account 486 (USA 353.1) – general plant – communications structures and equipment (currently approved and proposed 25-R2).

673. ATCO Electric did not propose changes to approved net salvage percentage parameters for the following accounts:

(a) Account 451 (USA 350.1) – transmission facilities – land rights (currently approved and proposed 0.0 per cent).

(b) Account 454 (USA 356) – transmission facilities – overhead conductors poles (wooden poles) (currently approved and proposed 50.0 per cent).

(c) Account 451.02 (USA 350.1) – McNeill converter station – land rights (currently approved and proposed 0.0 per cent).

(d) Account 483 (USA 391) – general plant – office furniture and equipment (currently approved and proposed 0.0 per cent).

(e) Account 483.2 (USA 391.1) – general plant – computer equipment and accessories (currently approved and proposed 0.0 per cent).

674. Intervening parties made no comments or alternative proposals with respect to the life-curve or net salvage recommendations for these nine accounts.

Commission findings

675. ATCO Electric provided no evidence to suggest that a departure from the approved net salvage percentages is required.

676. The Commission accepts ATCO Electric's continued use of the approved life-curve or net salvage percentages for these nine accounts.

8.10 Summary of approvals

677. The findings of the Commission with respect to ATCO Electric's 2015-2017 estimated average service lives, Iowa survivor curves and net salvage percentages, based on the reasons provided in the previous sections of this decision, have been summarized in the following two tables:

Table 29. Summary of proposed and approved 2015-2017 estimated average service lives, Iowa curves and net salvage per cents for ATCO Electric's transmission, McNeill converter station and general plant accounts

AET account	USA account	Description	ID 20272 - AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 - approved 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
		Transmission facilities				
451	350.1	Land rights	73-R4	0%	75-R3	0%
453	355	Poles and fixtures (wooden)	60-R2	-175%	60-R2	-90%
454	356	Overhead conductors poles (conductor wooden poles)	65-R3	-50%	65-R3	-50%
454.1	356	Overhead conductors towers (conductor steel towers)	65-R4	-50%	65-R4	-30%
455.1	354	Towers and fixtures (steel)	65-R4	-200%	65-R4	-25%
457	353	Substation equipment - AC	51-R2	-40%	53-R3	-15%
457.1	353	HVDC conductors-towers - HVDC (new)	53-R3	-40%	53-R3	-15%
		McNeill convertor station				
451.02	350.1	Land rights	2035 / 45-R4	0%	2035 / 45-R4	0%
453.02	355	Poles and fixtures	2035 / 45-R3	-50%	2035 / 45-R3	-90%
454.02	356	Overhead conductors poles	2035 / 45-R3	-50%	2035 / 45-R3	-50%
457.02	353	Substation equipment	2035 / 45-R2.5	-10%	2035 / 45-R2.5	-15%

AET account	USA account	Description	ID 20272 - AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 - approved 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
		General plant				
482	390	Structures and improvements	40-R2.5	-5%	50-R2.5	-5%
483	391	Office furniture and equipment	15-SQ	0%	15-SQ	0%
483.2	391.1	Computer equipment and accessories	5-SQ	0%	5-SQ	0%
484.01	392.1	Transportation equipment - category 1	8-L1.5	10%	8-L1.5	10%
484.02	392.2	Transportation equipment - category 2	9-L2	10%	9-L2	10%
484.03	392.3	Transportation equipment - category 3	18-S0	5%	18-S0	20%
484.04	392.4	Transportation equipment - category 4	10-L3	15%	10-L3	20%
484.05	392.5	Transportation equipment - category 5 (new)	4-S3	5%	9-L2	10%
484.06	392.6	Transportation equipment - category 6 (new)	8-S3	5%	18-S0	20%
485.01	394	Tools and instruments - category 1	8-SQ	0%	10-SQ	0%
485.02	394.1	Tools and instruments - category 2 (new)	4-SQ	0%	n/a	n/a
486	353.1	Communications structures and equipment	25-R2	-15%	25-R2	0%
489	399.2	Leaseholds (new)	8-SQ	0%	8-SQ	0%
496.1	n/a	Software - major (new)	7-SQ	0%	10-SQ	0%
496.2	n/a	Software- minor (new)	5-SQ	0%	7-SQ	0%
496.3	n/a	Software - desktop (new)	3-SQ	0%	3-SQ	0%

Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3.

Table 30. Summary of proposed and approved 2015-2017 estimated average service lives, Iowa curves and net salvage per cents for ATCO Electric's generation plant accounts

AET account	USA account	Description	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 approved 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
		Generation				
422	331	Hydro structures	2045 / 75-R2	-115%	2045 / 75-R2	-115%
423	332	Hydro reservoirs, dams and waterways	2045 / 100-R3	-115%	2045 / 100-R3	-115%
425	333	Hydro generators	2031 / 75-R3	-77%	2031 / 75-R3	-77%
426	334	Hydro accessory electrical equipment	2031 / 45-R3	-115%	2031 / 45-R3	-115%
427	335	Hydro miscellaneous plant equipment	2031 / 25-R2	-115%	2031 / 25-R2	-115%
432	336	Gas turbine structures	2017 / 50-R2	-125%	2018 / 50-R2	-125%
435	337	Gas turbine generators	2017 / 35-R2	-1%	2018 / 35-R2	-1%
436	338	Gas turbine accessory electrical equipment	2017 / 25-R1.5	0%	2018 / 25-R1.5	0%
437	339	Gas turbine miscellaneous equipment	2017 / 25-R1.5	0%	2018 / 25-R1.5	0%
442	341	Internal combustion structures				
		Chipewyan Lake	2028 / 50-R2	-6%	2028 / 50-R2	-6%
		Fawcet River	2029 / 50-R2	-22%	2029 / 50-R2	-22%
		Fort Chipewyan	2042 / 50-R2	-2%	2042 / 50-R2	-2%
		Garden River	2017 / 50-R2	-6%	2017 / 50-R2	-6%
		Indian Cabins	2037 / 50-R2	-3%	2037 / 50-R2	-3%
		Mobile Gen	2022 / 50-R2	-5%	2022 / 50-R2	-5%
		Narrows Point	2031 / 50-R2	-10%	2031 / 50-R2	-10%

AET account	USA account	Description	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 approved 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
		Palisades	2017 / 50-R2	-125%	2018 / 50-R2	-125%
		Peace Point	2033 / 50-R2	-9%	2033 / 50-R2	-9%
		Steen River Town	2032 / 50-R2	-5%	2032 / 50-R2	-5%
		Touchwood	2031 / 50-R2	-7%	2031 / 50-R2	-7%
444	342	Internal combustion fuel holders				
		Chipewyan Lake	2028 / 35-R3	-6%	2028 / 35-R3	-6%
		Fawcet River	2029 / 35-R3	-22%	2029 / 35-R3	-22%
		Fort Chipewyan	2042 / 35-R3	-2%	2042 / 35-R3	-2%
		Garden River	2017 / 35-R3	-6%	2017 / 35-R3	-6%
		Indian Cabins	2037 / 35-R3	-3%	2037 / 35-R3	-3%
		Narrows Point	2031 / 35-R3	-10%	2031 / 35-R3	-10%
		Palisades	2017 / 35-R3	0%	2018 / 35-R3	0%
		Peace Point	2033 / 35-R3	-9%	2033 / 35-R3	-9%
		Steen River Town	2032 / 35-R3	-5%	2032 / 35-R3	-5%
		Touchwood	2031 / 35-R3	-7%	2031 / 35-R3	-7%
445	343	Internal combustion generators				
		Chipewyan Lake	2028 / 25-R3	-6%	2028 / 25-R3	-6%
		Fawcet River	2029 / 25-R3	-22%	2029 / 25-R3	-22%
		Foggy Mountain	2033 / 25-R3	-9%	2033 / 25-R3	-9%
		Fort Chipewyan	2042 / 25-R3	-2%	2042 / 25-R3	-2%
		Garden River	2017 / 25-R3	-6%	2017 / 25-R3	-6%
		Indian Cabins	2037 / 25-R3	-3%	2037 / 25-R3	-3%
		Mobile Gen	2022 / 25-R3	-5%	2022 / 25-R3	-5%
		Narrows Point	2031 / 25-R3	-10%	2031 / 25-R3	-10%
		Palisades	2017 / 25-R3	-1%	2018 / 25-R3	-1%
		Peace Point	2033 / 25-R3	-9%	2033 / 25-R3	-9%
		Steen River Town	2032 / 25-R3	-5%	2032 / 25-R3	-5%
		Touchwood	2031 / 25-R3	-7%	2031 / 25-R3	-7%
446	345	Internal combustion accessory electrical equipment				
		Chipewyan Lake	2028 / 35-R2	-6%	2028 / 35-R2	-6%
		Fort Chipewyan	2042 / 35-R2	-2%	2042 / 35-R2	-2%
		Garden River	2017 / 35-R2	-6%	2017 / 35-R2	-6%
		Indian Cabins	2037 / 35-R2	-3%	2037 / 35-R2	-3%
		Narrows Point	2031 / 35-R2	-10%	2031 / 35-R2	-10%
		Palisades	2017 / 35-R2	0%	2018 / 35-R2	0%
		Peace Point	2033 / 35-R2	-9%	2033 / 35-R2	-9%
		Steen River Town	2032 / 35-R2	-5%	2032 / 35-R2	-5%
		Touchwood	2031 / 35-R2	-7%	2031 / 35-R2	-7%
447	346	Internal combustion miscellaneous electrical equipment				
		Fawcet River	2029 / 40-R3	-22%	2029 / 40-R3	-22%
		Fort Chipewyan	2042 / 40-R3	-2%	2042 / 40-R3	-2%
		Garden River	2017 / 40-R3	-6%	2017 / 40-R3	-6%
		Indian Cabins	2037 / 40-R3	-3%	2037 / 40-R3	-3%
		Narrows Point	2031 / 40-R3	-10%	2031 / 40-R3	-10%
		Palisades	2017 / 40-R3	0%	2018 / 40-R3	0%
		Peace Point	2033 / 40-R3	-9%	2033 / 40-R3	-9%

AET account	USA account	Description	ID 20272 AET proposed 2013 parameters (2015-2017) YFR/Int.Ret. Life-Curve	N.S.	ID 20272 approved 2015-2017 parameters YFR/Int.Ret. Life-Curve	N.S.
		Steen River Town	2032 / 40-R3	-5%	2032 / 40-R3	-5%
		Touchwood	2031 / 40-R3	-7%	2031 / 40-R3	-7%

Source: Exhibit 20272-X1101, GTA Schedules, Schedule 6-3.

9 Income taxes

678. ATCO Electric's summary of the income tax expense it is seeking to recover for 2015 through 2017, as well as the source of the observed year-over-year tax expense variance is provided in the table below:

Table 31. Summary of income tax expense

	2012 actual	2013 actual	2014 actual	2015 test period	2016 test period	2017 test period
	($ million)					
Income tax expense	25.8	24.8	22.6	31.6	45.8	49.9
Increases / (decreases) in test period				9.1	14.2	4.1
Due to:						
Increase in provincial income tax rate				0.4	-	-
Lower preferred dividend tax				(1.1)	-	
Increase / (decrease) in utility earnings				2.6	4.7	(2.7)
Impact of lower / (higher) tax deductions				7.2	9.1	6.9
Farms / irrigation				0.0	0.0	0.0
Increases / (decreases) in test period				9.1	14.2	4.1

Source: Exhibit 20272-1100, revised application, PDF page 129.

679. ATCO Electric has calculated its tax expense using the tax rates currently in place for the 2015-2017 test period including the increase in Alberta provincial corporate tax rate from 10 per cent to 12 per cent, that took effect July 1, 2015.The tax rates used in the calculation of income tax expense are provided in the table below.[426]

[426] Exhibit 20272-X1100, revised application, paragraph 272, PDF page 123.

Table 32. Summary of income tax rates

	2015	2016	2017
Federal income tax	15.00%	15.00%	15.00%
Provincial income tax	11.01%	12.00%	12.00%

Source: Exhibit 20272-1100, revised application, PDF page 124.

680. ATCO Electric is requesting that it be allowed to continue with the previously approved calculation of federal future income taxes (FIT), using the liability method.[427]

681. ATCO Electric utilizes a Canadian Revenue Agency (CRA) tax provision that allows a capital cost allowance to be applied in respect of the value of assets in advance of those assets actually going into service. ATCO Electric explained that "these [tax] provisions allow for [capital cost allowance] once an asset has been owned for a certain time, referred to as the 'rolling start' rule, and also allow for an election to be taken on assets acquired for use on a long term project, referred to as the 'long term project election.'"[428] The capital cost allowance that ATCO Electric elected to apply in 2013 and 2014 was not forecast in the utility's 2013-2014 GTA, but will be trued-up in the deferral applications for those years. ATCO Electric confirmed that in the current test years, the available capital cost allowance has been forecast, and any difference between the forecast amount and the actual capital cost allowance claimed in the test period will be trued-up in the deferral applications for those years.[429]

682. The RPG analyzed ATCO Electric's GTA tax schedules, and concluded that ATCO Electric has been using capital cost allowance to generate negative taxable income but has not established a tax loss carry forward for utilization in future years. It appeared to suggest that because current income tax amounts are not subject to deferral account treatment, any triggering of a tax loss through the excessive use of capital cost allowance in 2013 and 2014 that resulted in the erosion of tax pools which would otherwise have been available to offset future taxes is not reviewable by the Commission.[430]

683. The RPG further argued that ATCO Electric has added to the FIT liability for 2013-2014 only the approved FIT, as opposed to the actual FIT expense that was recorded for each year. The RPG noted that this treatment was consistent with prior years, but the result of this treatment is an understatement of the FIT liability that will result in a future understatement of no cost capital and the amount of FIT that will ultimately be available to offset rates paid by customers.[431]

[427] Exhibit 20272-X1100, revised application, paragraph 271, PDF page 123.
[428] Exhibit 20272-X1100, revised application, paragraph 290, PDF page 128.
[429] Exhibit 20272-X1100, revised application, paragraph 290, PDF page 128
[430] Exhibit 20272-X0789, RPG evidence, paragraph 307, PDF pages 108-109.
[431] Exhibit 20272-X0789, RPG evidence, paragraph 308, PDF page 109.

684. The RPG recommended that:[432]

1) any current income tax losses that are not properly adjusted for in the 2013 or 2014 Deferral Account Applications be added to 2015, 2016 and 2017 temporary differences to represent additional available deductions in the year;
2) customers not bear the risk for any potential expiry of these losses on an actual basis if AET has triggered tax losses for corporate purposes; and
3) that AET add the full amount of actual 2013 and 2014 future income taxes to the FIT liability in Schedule 29-4.

685. ATCO Electric stated that the recommendation to include the impacts of any income tax losses from previously approved test periods should be dismissed. It claimed that the RPG is attempting to retroactively adjust the income tax expense that was determined in ATCO Electric's final rates for the 2013-2014 GTA test period. ATCO Electric stated that "to the extent that AET experiences higher or lower temporary timing differences used in determining taxable income for non-deferral related accounts (outside of those accounts which are subject to deferral account treatment), there is no risk to customers for the expiration of these tax losses as AET has accepted the forecast risk and the associated variance with these temporary timing differences."[433]

686. ATCO Electric argued that the RPG's recommendation to use the actual 2013 and 2014 federal FIT liability to reduce rate base through inclusion in no cost capital ignores the regulatory principles related to the treatment of no cost capital. ATCO Electric explained that it includes no cost capital only for those balances which were approved and collected in rates, as opposed to the actual amounts that are recorded. It added that this regulatory treatment was confirmed in ATCO Electric's 2013-2014 GTA.[434] [435]

687. The RPG argued that in direct assigned capital deferral account (DACDA) applications, adjustments for variances only pertain to depreciation and capital cost allowance but do not account for the variances in ES&G or for removal and abandonment costs. It added that ES&G and removal and abandonment costs are reviewed as constituent costs of capital additions, but that a DACDA does not consider these costs for the purposes of calculating the adjusted income tax expense.[436]

688. The RPG stated that the capital cost allowance claim is the final deduction taken for tax purposes and therefore is the deduction that ultimately creates any tax loss recorded. The RPG submitted that "it is totally reasonable that the tax losses created by this [capital cost allowance] should also be addressed as part of the deferral account process. In the absence of addressing these amounts and including them within the regulatory schedules, [ATCO Electric] will unfairly benefit from its under-forecasting of temporary differences and random elections not otherwise approved by the Commission."[437]

689. The RPG recommended that ATCO Electric be directed to true up all temporary differences related to capital, including ES&G and removal and abandonment costs, as part of its

[432] Exhibit 20272-X0789, RPG evidence, paragraph 323, PDF pages 112-113.
[433] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 186-188.
[434] Decision 2013-358, paragraphs 997-999.
[435] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 186-188.
[436] Exhibit 20272-X1297, RPG argument, paragraph 422, PDF page 137.
[437] Exhibit 20272-X1297, RPG argument, paragraph 434, PDF page 140.

deferral account application. It was of the view that deferral treatment should apply to the 2013 and 2014 deferral account application as well.[438]

690. To the extent the Commission does not fully approve its recommendations related to income tax, the RPG requested that the Commission direct ATCO Electric to reverse the use of the rolling start adjustment for income tax purposes. The RPG stated that this adjustment was not approved or applied for in prior years and therefore should not be reflected in ATCO Electric's regulatory tax pools.

Commission findings

691. The RPG has requested that the Commission direct ATCO Electric to add current income tax losses, that are not dealt with in the 2013 and 2014 DACDA application, to the 2015, 2016 and 2017 temporary differences to increase available deductions in those years. ATCO Electric argued that this is a retroactive adjustment to the income tax expense that was determined as part of its final rates for the 2013-2014 test period.

692. As a general proposition, the Commission is not predisposed to dictate the tax strategies employed by ATCO Electric in the operation of its business and for this reason will not direct the utility to account for its tax losses in the manner requested by the RPG. However, should the Commission become aware that any rate-base rate of return regulated utility is employing tax strategies for the purpose of cross-subsidizing any affiliate to the detriment of its own ratepayers, the Commission will take such steps as it considers necessary and in the public interest to prevent such conduct.

693. The RPG also requested that the Commission direct ATCO Electric to true-up FIT balances with actuals. The Commission ruled on this matter in ATCO Electric's prior GTA, as follows.[439]

> 997. The Commission reviewed schedules 7-2 (Schedule of Transmission Income Taxes) and 29-3 (Schedule of Future Income Taxes) of the supplementary revenue requirement schedules that were filed in conjunction with the omissions and updates filing, and questioned why the future tax amounts for 2011 and 2012 in Schedule 29-3 did not agree with the corresponding cross referenced amounts in Schedule 7-2. [footnotes removed]
>
> 998. In response, ATCO Electric advised that the current year future tax balances in Schedule 29-3, of $6.7 million and $10.9 million for the years 2011 and 2012, reflect those final amounts which were approved and collected in rates as part of ATCO Electric's 2011-2012 GTA compliance filing, adding that it only includes in no cost capital those balances which were approved and collected in rates, as opposed to the actual amounts that it incurs. [footnotes removed]
>
> 999. This explanation is valid because the amount of FIT included in no cost capital should include the amounts which were approved and collected in rates. The AESO has paid the approved amounts and these approved amounts should be reflected in the calculation of mid-year no cost capital and ultimately the return on rate base.

[438] Exhibit 20272-X1297, RPG argument, paragraph 437, PDF page 141.
[439] Decision 2013-358, paragraphs 997-999.

694. The Commission considers that customers should only receive credit in the no cost capital account for the future income taxes they actually pay as part of rates. This is the nature of no cost capital. Even though actual future income tax expense for 2013 and 2014 was more than forecast, customers did not pay these actual future income tax expense amounts through rates. Instead, customers paid lesser amounts. Consequently, the amount of no cost capital provided by customers for 2013 and 2014 is equal to the forecast approved amounts for these years. The same would be true if the actual future income tax expense for 2013 and 2014 had been less than the forecast.

695. The Commission is not persuaded by the RPG's submissions that it should alter its previous determination. The RPG's proposal to have ATCO Electric update its no cost capital schedules to reflect actual 2013 and 2014 FIT balances is denied. The RPG requested that deferral account treatment be directed for temporary differences related to capital generally, including ES&G and removal and abandonment costs incurred in connection with non-direct assigned projects.

696. DACDA proceedings are primarily intended to address differences between forecasts and actuals on projects assigned by the AESO. The Commission has already stated that the deferral for direct assigned projects should include variances on all temporary tax adjustments, such as ES&G and removal and abandonment, as provided below:

> 60. Consistent with previous treatment of direct assigned capital projects deferral accounts, ATCO Electric proposed a deferral account for direct assigned capital projects additions, direct assigned capital projects work in progress and direct assigned capital projects contributions. The deferral would account for the revenue requirement impact (return, depreciation, and income tax components) associated with the differences between the actual and forecast approved direct assigned capital projects additions, direct assigned capital projects work in progress and direct assigned capital projects contributions. Details of the calculation related to the balance in the 2011 direct assigned capital projects deferral account are included in Schedule 2.0 of Section 32 of the application. ATCO Electric added that carrying costs will be calculated in accordance with the AUC's Rule 023.[440] [441] [emphasis added]

697. The Commission considers that the purpose of the direct assigned capital projects deferral account is to protect both ATCO Electric and customers against all revenue requirement impacts related to differences between actual and forecasted direct assigned project costs. The Commission also considers that this includes any and all differences related to income tax and its various components, as ATCO Electric acknowledged in its 2013-2014 GTA. To the extent that there are differences between actual and forecast costs for ES&G and removal and abandonment costs that relate to direct assigned projects, the Commission finds that these should be accounted for in the 2013-2014 DACDA. The Commission directs ATCO Electric, in the compliance filing, to identify and provide these differences. The Commission also directs ATCO Electric to indicate whether these differences have been reflected in the current DACDA application and, if not, to describe how ATCO Electric will reflect them in that proceeding.

698. The Commission does not consider that it is reasonable to direct ATCO Electric to include all tax temporary differences related to non-direct assigned projects in its DACDA application.

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[440] AUC Rule 023: *Rules Respecting Payment of Interest*.
[441] Decision 2013-358, paragraph 60.

699. The Commission denies the RPG's request to reverse the use of the rolling start adjustment. ATCO Electric could take advantage of the election notwithstanding that it did not apply for approval to do so in the 2013-2014 GTA. Elections with respect to income tax depend upon the income tax situation the entity is in, as well as the income tax strategy the entity chooses to pursue. As stated earlier, the Commission is not predisposed to dictate the tax strategies employed by ATCO Electric in the operation of its business. The Commission is also reassured by ATCO Electric's statement that:

> AET would like to clarify that there is no negative impact to customers for the rolling start adjustment of $274.5 million. AET has claimed in years prior to 2015 the CCA eligible under the rolling start election rule for Direct Assigned capital projects. For years prior to 2015, the CCA claim made under the rolling start election rule, as outlined in AET's GTA Application will be trued up with customers as part of AET's 2013-2014 deferral application (Proceeding ID 21206).[442]

700. Based on this statement, the Commission considers that customers will receive the benefit of the rolling start adjustment through the 2013-2014 DACDA. The Commission directs ATCO Electric, as part of the compliance filing, to demonstrate where this benefit is reflected in the ongoing 2013-2014 DACDA proceeding.

10 Revenue offsets

701. In the application, ATCO Electric provided Schedule 8-1 with information on revenue offsets forecast for the test years. The table below summarizes these revenue offset forecasts by category:

[442] Exhibit 20272-X1120, page 180.

Table 33. Summary of transmission revenue offsets

Description	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
	($ million)					
Affiliate revenue						
Alberta PowerLine	-	-	-	5.1	10.3	11.5
ATCO Power	0.1	0.3	0.4	10.5	2.9	0.4
ATCO Energy Solutions	0.3	0.3	0.3	9.7	0.4	0.4
ATCO Electric Distribution						
Telecommunications	-	-	2.7	1.3	1.4	1.5
Buildings - SOC	-	-	0.0	0.9	0.9	0.9
Joint pole	0.9	0.8	0.6	0.6	0.6	0.6
Other	-	-	0.7	1.3	1.3	1.3
Other	1.1	0.5	(0.1)	0.4	0.4	0.4
Total affiliate revenue	2.4	1.9	4.7	29.7	18.1	16.9
Facility charges	0.8	0.8	0.8	0.8	0.5	0.5
SOP revenue	0.3	0.3	0.7	0.3	0.3	0.3
Other revenue	0.3	0.4	0.5	0.5	0.5	0.5
Total revenue offsets	**3.9**	**3.4**	**6.7**	**31.3**	**19.3**	**18.1**

Source: Based on Exhibit 20272-X1101, Schedule 8-1 Transmission Revenue Offsets.

702. Affiliate revenue is collected as result of work done by ATCO Electric personnel for affiliates. This revenue is intended to recover ATCO Electric's direct and indirect costs of providing the services, in accordance with the ATCO Inter-Affiliate Code of Conduct. The majority of the affiliate revenue forecast for the test period was for providing services to Alberta PowerLine, ATCO Energy Solutions, ATCO Power and ATCO Electric Distribution.[443]

703. "[T]hese revenues are offset by affiliate cost of goods sold which are included in operations costs; as a result, there is no material impact on revenue requirement as these revenues increase or decrease."[444]

704. Facility charges serve to recover ATCO Electric costs incurred when constructing and operating facilities on customer sites that have an Industrial System Designation. ATCO Electric explained that "[i]n Decision 21042-D01-2015, AET [ATCO Electric] received AUC approval to sell its Steepbank River Substation assets to Suncor. These assets are currently subject to a Facilities Charge Agreement (FCA). As a result of the sale, these assets will no longer be required to provide utility service. As such, AET has removed the assets from rate base beginning in 2016 as well as the corresponding forecast revenue offset. No new facility charges are forecast in the Test Period."[445]

[443] Exhibit 20272-X1100, application, paragraphs 294-295, PDF page 132.
[444] Exhibit 20272-X1100, application, paragraph 294, PDF page 132
[445] Exhibit 20272-X1100, application, paragraph 293, PDF page 131.

705. Services to outside parties (SOP), such as road moves and work for the AESO, are requested on behalf of external parties, who are required to compensate ATCO Electric for the cost of the work. These amounts are then recorded as cost of goods sold and as operating costs.[446] ATCO Electric explained that the other revenue category shown in the table above consists of telmark tower revenue.

706. The RPG expressed concerns over potential cross-subsidization which could result from "[s]hared [ATCO Electric] corporate and/or ATCO/CU head office costs and capital related overheads, to the extent [they are] not allocated appropriately to APL [Alberta PowerLine]."[447]

707. ATCO Electric responded that the RPG has not provided any information to support its claim that cross-subsidization is occurring. ATCO Electric submitted that "adherence to the appropriate provisions of the Code of Conduct will ensure that ratepayers are kept neutral as a result of these transactions."[448]

Commission findings

708. The Commission notes that determinations on telecommunications cost allocations found at Section 7.3 of this decision may affect proposed revenue offsets considered under this section for telecommunications services provided to ATCO Electric Ltd.'s distribution arm. ATCO Electric is directed to incorporate those changes into the compliance filing.

709. The ATCO Inter-Affiliate Code of Conduct requires the charging of "… fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads"[449] for affiliate services provided on the "cost recovery basis."

710. In Section 16 of this decision, which addresses affiliate services provided by ATCO Electric to Alberta PowerLine, the affiliate overhead rate of 70 per cent for capital projects was applied to labour costs. Fringe benefit costs were then added to the proposed affiliate services cost forecast. The Commission considers that overhead recovery is necessary to ensure that ATCO Electric is compensated for smaller, less direct costs that are less variable and not economical to individually track so as to comply with the ATCO Inter-Affiliate Code of Conduct.

711. In an updated IR response,[450] ATCO Electric provided a schedule of transmission affiliate overhead rate calculations. This schedule displayed the overhead recovery rates applied in the provision of affiliate O&M services and construction projects, as being 40 per cent and 70 per cent, respectively. The schedule included revised overhead recovery rates resulting from application updates filed during the course of the proceeding. The Commission notes that the forecast effective overhead rate for O&M services ranged from 41per cent to 63 per cent as compared to the 40 per cent applied to the forecasts for provision of affiliate O&M services. Further, the forecast effective overhead rate for construction projects ranged from 64 per cent to

446 Exhibit 20272-X1100, application, paragraphs 296-298, PDF pages 132-133.
447 Exhibit 20272-X0789, RPG evidence, paragraphs 413-414, PDF pages 134-135.
448 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 198.
449 Decision 2003-040: ATCO Group, Affiliate Transactions and Code of Conduct Proceeding, Part B: Code of Conduct, Application 1237673-1, May 22, 2003., Definitions, page 3.
450 Exhibit 20272-X1106, Updated response to IR AET-AUC-2015DEC30-003, Attachment 1.

80 per cent as compared to the 70 per cent applied to forecasts for provision of affiliate construction services.

712. The Commission observes that while the RPG expressed concerns regarding cross-subsidization, it did not challenge the overhead rates ATCO Electric charges in respect of shared services. No other parties provided comments on affiliate overhead recoveries.

713. For the above reasons, the Commission considers that affiliate overhead rates should be examined as part of the next GTA proceeding to determine whether they are adequate. The Commission directs ATCO Electric to provide a detailed assessment of affiliate overhead burden rates comparing the current rates applied and their supporting basis, to the forecast effective rate that results from forecast overhead costs and related forecast activity levels. An examination of five years of historical information shall be incorporated for comparison purposes.

11 Rate base

714. Capital costs in the revenue requirement include return, depreciation and (if applicable) income tax. These costs are driven by both the size of the rate base (less customer contributed assets and no-cost capital) and the annual rates applicable to return, depreciation and income tax.

715. Rate base is the utility equivalent of net property, plant and equipment, with an additional component for necessary working capital. The rate base of a utility increases when additions are made to property, plant and equipment, and decreases when capital assets are retired or their costs are otherwise adjusted. Rate base also decreases when depreciation is charged against property, plant and equipment. A utility's return is calculated on the basis of mid-year net rate base. The difference between mid-year rate base and mid-year net rate base is generally equal to the amount that has been calculated for mid-year no cost capital and mid-year net customer contributions.

716. Depreciation aspects of rate base determination are addressed in Section 8 of this decision and mid-year necessary working capital is addressed in Section 12 of this decision. Capital property additions, retirements and adjustments, customer contributions and CWIP, are addressed in this section of the Commission's decision. General capitalization policies are addressed in Section 11.2, below.

11.1 Project management and regulatory matters

717. This section describes various inter-related[451] aspects of this GTA, including the Commission's role in the approval and oversight of electric transmission project development in Alberta, generally. It also contains the Commission's determinations regarding ATCO Electric's compliance with directions contained in Decision 2014-283, which determined the company's 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances application, and contains a discussion of various intervener policy recommendations.

[451] Notably, risk management practices can relate to the accuracy of forecasts. According to FTI in Exhibit 20272-X0819 in response to CCA-AUC-2016FEB01-023 at PDF page 15, as ATCO Electric improves its risk management and project control systems, its forecast accuracy will also improve.

11.1.1 Transmission rate increases

718. A significant portion of the RPG's evidence was dedicated to analyzing recent transmission rate increases, which the group viewed as being "substantial," in addition to forecast increases. In the RPG's view, past and future transmission rate increases could affect generation development and the energy market in Alberta and result in "unneeded surplus capacity."[452]

719. Section 3 of the RPG evidence compared forecast load growth to actual load growth. In the RPG's view, its analysis demonstrates that the AESO is consistently overly optimistic in its estimates of energy and load growth. This, in turn, creates a situation in which new transmission infrastructure is constructed ahead of actual need.

720. Section 4 of the RPG's evidence contained an analysis of the transmission costs at which different customer load types (large industrial, medium industrial, and large commercial) may be incented to develop behind-the-fence (BTF) generation. In this regard, the RPG expressed a concern that as more customers develop BTF generation, resultant transmission rate increases for remaining customers could incent still more BTF generation which, in turn, "further exacerbates the problem." This section of the RPG evidence also provided a comparison of Alberta transmission rates to those in other jurisdictions in North America. Based on its analysis, the RPG concluded that the ratio of transmission costs to the wholesale price is significantly higher in Alberta than in a sample of state jurisdictions in the United States of America.

721. The RPG also provided an example of projected differences in new transmission line requirements under a 1.3 per cent energy growth scenario as compared to a four per cent energy growth scenario. It also analyzed current transmission capacity on several new transmission lines in Alberta and utilization levels in 2017 and 2027 based on the single worst contingency that could affect each transmission line. Based on these analyses, the RPG concluded that utilization of existing transmission infrastructure currently ranges from three to 14 per cent and that it could be many generations before existing surplus capacity is used.

722. In the RPG's view, ATCO Electric has the option of working with the AESO to defer transmission projects wherever this can be done without a material impact on safety and reliability. In light of this, the RPG recommended that the factors described in sections 3 to 5 of its evidence should be considered by the Commission in its determination of ATCO Electric's revenue requirement.[453] More specifically, the RPG submitted that this proceeding should test "the need and timing for every project that is in progress," that "the forecast capital expenditures should reflect realistic expenditure patterns" and, where an ISD can be deferred, "the project and associated capital should be deferred."[454] The RPG, however, did not highlight specific projects and associated costs identified in this application which should be deferred.

723. Finally, the RPG recommended that the Commission conduct a more in-depth review of transmission growth and suggested that this review could provide policy and regulatory options for this proceeding and future GTAs and DACDAs.[455]

[452] Exhibit 20272-X0789, RPG main evidence, PDF page 8.
[453] Exhibit 20272-X0789, RPG main evidence, PDF pages 12-32.
[454] Exhibit 20272-X0789, RPG main evidence, PDF page 31.
[455] Exhibit 20272-X0789, RPG main evidence, Appendix C, PDF pages 173-178.

724. ATCO Electric did not directly address the RPG's evidence related to load growth projections and transmission capacity. It generally stated in its rebuttal that this proceeding is not the correct forum for examination of the RPG's evidence regarding these factors and requested that the Commission confirm that these matters will not be addressed and are not relevant to this proceeding.[456]

725. ATCO Electric noted in its rebuttal evidence that project forecasts were updated throughout this proceeding in response to information from the AESO and from customers and to align with the AESO's Long-Term Transmission Plan, which was updated on November 15, 2015. ATCO Electric also noted that the AESO Connection Process is designed to lead to the lowest possible transmission capital expenditures by reviewing the possible solutions and moving forward with the most cost effective solution that is technically viable.[457]

726. In argument, the RPG requested "that the Commission initiate a generic proceeding on AESO energy forecasts, rate levelization and other matters, to address the observed and expected increases in overall transmission rates."[458] The RPG considered that rate levelization could be designed to match the value of services rendered over the lifetime of an asset so that current customers will not pay for the large transmission infrastructure costs of recent years when that transmission infrastructure will benefit customers for 60 to 70 years. In its view, rate levelization could also reduce the incentive for customers to develop BTF generation.[459]

727. In reply argument, ATCO Electric stated that the issues of transmission rate increases and their impacts brought forward by the RPG do not relate to ATCO Electric's 2015-2017 GTA and "should not have any bearing on the disposition of issues before the Commission for consideration in this proceeding." ATCO Electric also stated that these issues affect parties who were not part of this proceeding and, as such, it would be inappropriate to make any determinations regarding the RPG's requested generic proceeding without giving other parties an opportunity to provide input.[460]

Commission findings

728. The rates of Alberta TFOs are not charged directly to customers but rather to the AESO, which, in turn, flows the cost of TFO rates to either directly connected industrial customers or to regulated distribution facility owners through its tariff.[461] Further, the AESO, and not the TFO, is responsible for planning and bringing forward need applications for new transmission facilities. A TFO must respond to a direction of the AESO to construct new facilities when asked, unless doing so would put its facilities, or the safety of the TFO's employees, or the public, at risk.

729. The TFO includes an aggregate capital addition estimate when it develops its revenue requirement forecast for its transmission tariff and the Commission is responsible for approving the tariff that the TFOs propose to charge to the AESO for the use of their transmission facilities. Section 25(3) of the *Transmission Regulation* expressly confirms that the TFO must demonstrate that its tariff is just and reasonable and that the Commission retains responsibility to determine a TFO's or other person's prudence in managing a transmission facility project.

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456 Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 103.
457 Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 104-105.
458 Exhibit 20272-X1297, RPG argument, PDF page 10.
459 Exhibit 20272-X1297, RPG argument, PDF pages 20-28.
460 Exhibit 20272-X1312, ATCO Electric reply argument, PDF pages 12-13.
461 Sections 30 and 37 of the *Electric Utilities Act*.

730. Commission approval of the prudence of transmission project costs is sought after the investments have been made and the facility is in service. The current procedure is largely a backward-looking, after-the-fact assessment for future rate-making purposes with the consequential difficulty of denying a major investment after the investment has occurred. Direct assigned capital additions are subject to a prudence review in a separate proceeding.

731. In this proceeding, the interveners have provided evidence regarding load growth forecasts and their effect on transmission rates. The interveners recommended that the Commission evaluate ATCO Electric's GTA with that evidence in mind. The interveners have provided that evidence, understanding that this GTA may not be the forum to address all of the issues they have raised, and have recommended that the Commission initiate a generic proceeding to examine those issues.

732. With respect to the relevance of the interveners' evidence in this GTA, while the Commission agrees that the issue of increasing transmission rates raised by the interveners is affected by components of the revenue requirement proposed in this application, the Commission must evaluate the merits of the application before it by analyzing the evidence on the record as it pertains to the applied-for revenue requirement. The Commission evaluates the merits of an application by weighing various factors affecting the public interest including, but not limited to, rate stability, minimization of rate shock and intergenerational inequity against the TFO's right to the reasonable opportunity to recover prudently incurred costs. As stated above, the Commission must approve a just and reasonable tariff. The Commission cannot, however, make a determination on this rate application solely on the basis of evidence of rising transmission costs.

733. The Commission notes that there are ongoing initiatives to address the oversight and recovery of transmission capital project costs, including:

- Transmission Facilities Cost Monitoring Committee (TFCMC) review: The TFCMC was established by Ministerial Order 64/2010 pursuant to Section 7 of the *Government Organization Act*, RSA 2000, c. G-10, on July 31, 2010. Its mandate, as set out in the ministerial order, is to (1) review records that relate to the cost, scope, schedule and variances of transmission facility projects that are forecast to cost in excess of $100.0 million; (2) prepare reports that summarize the records it reviews and the status of the transmission facility projects; (3) provide at least two reports to the organizations represented on the TFCMC each calendar year; (4) provide at least one report to the ministers of Energy and Service Alberta each calendar year; and (5) not delay or slow the development of transmission facility projects.
- Transmission rate treatments to recover electric transmission related investments, Proceeding 2421, a coordinated process to examine alternative approaches and rate treatments that might mitigate or smooth the impact on consumers of rate or bill increases, while ensuring regulated utilities continue to have an opportunity to earn a fair return on capital. This proceeding is ongoing.
- The cost oversight management pilot project, which examined a new approach to electricity transmission cost review and seeks to provide third-party expert review and comment on transmission project costs at specific stages of a transmission project from planning through construction completion. The pilot project is complete.
- Commission-Initiated proceeding to address the customer advancement cost component of the AESO's tariff, Proceeding 20922: This proceeding was initiated following

Commission Decision 3473-D02-2015 on the 2014 AESO Tariff Compliance Filing. This proceeding is examining the role of customer requests in driving the timing of transmission projects and how this can be reflected in the AESO tariff. This proceeding is ongoing.

734. The Commission does not consider that further direction on these matters is required in this proceeding.

11.1.2 Forecasting accuracy on direct assigned projects

735. The RPG submitted evidence on ATCO Electric's forecasting accuracy for operation and maintenance expenditures, direct assigned capital projects and capital maintenance projects. The RPG evidence with respect to forecast accuracy on operations and maintenance expenditures is addressed in Section 7 and forecasting accuracy on capital maintenance projects is addressed in Section 11.4.2.2 of this decision. This section addresses ATCO Electric's forecasting accuracy with respect to direct assigned projects.

736. The RPG expressed a concern that ATCO Electric has no mechanism to adjust for uncertainty in direct assigned project execution arising from either ISD, or economic, uncertainty. It contrasted ATCO Electric's apparent lack of means to deal with such uncertainty with the approach employed by AltaLink, which uses an uncertainty adjusted forecast for capital expenditures. According to the RPG, without adjusting for uncertainty, ATCO Electric's forecasts may be overstated.[462]

737. In argument, the RPG asserted that ATCO Electric's applied-for capital expenditures and capital additions were less than the actual amounts in every year between 2005 and 2014 with the exception of 2009, and that the observed difference between applied-for and actual amounts was caused by project delays or cancellations. Accordingly, the RPG requested that the Commission direct ATCO Electric to implement an uncertainty adjusted capital forecasting model for future GTAs.[463]

738. In a related submission, FTI analyzed ATCO Electric's historical forecasting accuracy on capital expenditures and capital additions for the 2006 to 2014 time period. In doing so, it concluded that observed variances ranged from -41 per cent to +107 per cent for the utility's capital expenditure forecasts and from -51 per cent to +365 per cent for capital addition forecasts. FTI stated that variances of this magnitude are outside of the accuracy ranges required by proposal to provide service (PPS) and needs identification document (NID) estimates. It also asserted that "most typically, the data indicates that ATCO Electric's forecasts are overstated in comparison to actual values with the greatest variances (both positive and negative) occurring on projects in excess of $100 million" and that forecasts of capital expenditures typically exceeded actual expenditures by more than 20 per cent.[464]

739. According to FTI, ATCO Electric, as a TFO with decades of experience in the development and delivery of transmission facility projects, should have both access to historical project data and an understanding of forecasting challenges. Consequently, it should be capable of adequately forecasting costs to a "more reasonable level," by using mechanisms such as

[462] Exhibit 20272-X0789, RPG main evidence, PDF pages 32-33.
[463] Exhibit 20272-X1297, RPG argument, PDF page 158-159.
[464] Exhibit 20272-X0784, FTI evidence, PDF pages 72-73.

uncertainty adjusted forecasts to account for changes in ISDs or other delays or advances in the project.[465]

740. FTI evaluated forecast capital expenditures and capital additions for six projects on the basis of the reasonableness of the estimates in relation to (1) established benchmarks, (2) trend analyses, (3) calculated effects of observed trends to cost and schedule within the test period, and (4) budget and schedule uncertainty. FTI selected the projects using the following criteria:

- The project was directly assigned by the AESO.
- The majority of the project expenditures fell within the test years.
- The sample size was adjusted as ATCO Electric updated its application to remove projects which were cancelled, on hold or which were completed in 2015.[466]

741. Based on the results of its reasonableness evaluation, FTI recommended reductions to capital expenditure forecasts for the following projects: Jasper Interconnection ($34.07 million reduction); Thickwood Development project ($48.84 million reduction); EATL ($7.8 million reduction to 2016 forecast); and Algar Area Expansion ($1.8 million reduction to 2015 forecast).

742. FTI also recommended reductions to forecasts for the following capital additions projects: EATL ($3.3 million reduction in 2013 and $7.8 million reduction in 2016); and Algar Area Expansion ($1.8 million reduction in 2015).[467]

743. These recommendations were made prior to ATCO Electric's application update on February 23, 2016.

744. The RPG noted that an update to ATCO Electric's application had been submitted after the filing of intervener evidence and argued that the overall number and significance of updates to forecasts that were filed throughout the proceeding demonstrates that the level of certainty for ATCO Electric's direct assigned capital forecasts is "very low."[468] The RPG requested "that the Commission direct ATCO Electric to update its direct assigned capital forecast to reflect the most current forecast of direct assigned capital and in-services dates, adjusted for any known changes" and use the most current forecast of its direct assigned projects consistently throughout the compliance filing.[469]

745. The RPG also recommended that ATCO Electric be directed to work with the AESO on projects which are in early stages to confirm if the projects can be further delayed. For projects where the AESO continued to support the ISD, a detailed justification for why this ISD is still valid should be provided in the compliance filing to this decision.[470]

746. In rebuttal and argument, ATCO Electric stated that it updated its capital forecasts throughout this proceeding as new information became available. It noted that these updates resulted in decreases in direct assigned project forecasts. In ATCO Electric's view, the submission of these updates confirms that it does, in fact, review and revise its project forecasts and, where necessary, removes projects from its forecasts to account for uncertainty. ATCO

[465] Exhibit 20272-X0819, CCA-AUC-2016FEB01-023, PDF page 15.
[466] Exhibit 20272-X0819, CCA-AUC-2016FEB01-024(a), PDF pages 16-17.
[467] Exhibit 20272-X0784, FTI evidence, PDF pages 74-96.
[468] Exhibit 20272-X1307, RPG reply argument, PDF page 104.
[469] Exhibit 20272-X1297, RPG argument, PDF pages 17 and 160.
[470] Exhibit 20272-X1297, RPG argument, PDF page 36.

Electric also argued that it includes potential ISD delays and potential delays in the planning, regulatory, preconstruction and construction stages of the project, in its capital forecasts based on its best estimate for individual projects and defers capital expenditures and additions to align with anticipated delays.[471] [472] During the oral hearing, ATCO Electric further clarified how it forecasts for capital costs, noting that the forecast is "built from the ground up" and is conservative (meaning contingency is built into the schedules, not into project costs which are forecast to be as accurate as possible[473]). It also indicated that the schedules' forecasts are confirmed based on discussion with the AESO and customers.[474]

Commission findings

747. The Commission reduced ATCO Electric's 2013-2014 capital expenditure forecasts by nine per cent in the last GTA to account for uncertainty arising from external influences.[475] The Commission is not persuaded that similar action is required in this case. ATCO Electric has repeatedly updated its forecasts since it first filed its rate application on March 16, 2015. The number and nature of these updates has far exceeded what the Commission usually observes in a GTA proceeding. As a result, the Commission has been provided with forecast information that is unusually current. The Commission considers it reasonable to expect these forecasts to be more accurate than ones based on older or outdated information.

748. The Commission finds there is sufficient information on the record to evaluate the reasonableness of ATCO Electric's forecast capital expenditures and additions, bearing in mind the uncertainty inherent in all forecasts. Additionally, the Commission notes that the majority of capital additions are subject to true-up in the direct assigned deferral account. The Commission will not direct ATCO Electric to implement an uncertainty adjusted capital forecasting process at this time.

749. Where possible, subject to certain important exceptions discussed more fully below, the Commission relies on the best available information when rendering a decision. As the Board stated in Decision in 2006-004,[476] the best available information includes information which has been updated after the preparation of the initial application, including actuals:

> 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

[471] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 109-110.
[472] Exhibit 20272-X1298, ATCO Electric argument, PDF pages 126-127.
[473] Transcript, Volume 10, page 1761.
[474] Transcript, Volume 3, pages 384-387.
[475] Decision 2013-358, paragraphs 773-777.
[476] Decision 2006-004: ATCO Gas, 2005-2007 General Rate Application, Phase I, Application 1400690-1, January 27, 2006.

> 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 conditions. Properly considered, this should reduce the initial forecasting risk to the utility and reduce the possibility of overpayment by ratepayers.[477]

750. However, the Commission must balance this with the regulatory principles of prospective rate-making and the applicant's right to a timely decision based on the information filed within the evidentiary portion of the proceeding. The Commission considers that RPG's request for updated direct assigned forecasts in the compliance filing would be generally inconsistent with prospective rate-making. The Commission will not direct ATCO Electric to globally update its direct assigned forecasts in the compliance filing. However, as discussed in the applicable sections below, in some cases, the Commission requires additional information and updates in order to make a determination on project forecasts.

751. The RPG recommended that ATCO Electric be directed to re-evaluate ISDs or provide justification for ISDs from the AESO in the compliance filing. The Commission ruled as follows when this issue was raised by the RPG in the previous ATCO Electric GTA:

> 387. The Commission has heard evidence that ATCO Electric has proactively been in discussions with the AESO regarding project ISDs. However, the Commission understands the issue for rate payers to be that they do not have a venue in which to participate in the process and that they are unsatisfied with the results that have been produced by the current approach that ATCO Electric and the AESO have used as the context for these project prioritization discussions.
>
> 388. As set out in ATCO Electric's evidence, it is already consulting with the AESO so there is no need for the Commission to direct ATCO Electric to do what it is already doing and what the Commission expects it will continue to do. Notwithstanding, the Commission considers the approach advocated by the RPG to include rate payers in the process, and to plan transmission on the basis of overall project prioritization, to have merit. However, as set out in Section 17 of the Electric Utilities Act and Part 2 of the Transmission Regulation, system planning is clearly the responsibility of the AESO. Consequently, apart from encouraging the AESO to consider this approach, the Commission cannot direct the AESO to engage in this process.[478]

752. As stated above, the Commission will evaluate the forecast capital expenditures and additions for direct assigned projects using the best available (or most up-to-date) information, on a project by project basis. This analysis can be found in Section 11.4.1 of this decision. FTI's recommendations will be addressed in that section, as applicable.

[477] Decision 2006-004, page 3.
[478] Decision 2013-358, paragraphs 387-388.

11.1.3 Forecasting on a "zero-based" approach for capital FTEs and capital maintenance

753. In Decision 2013-358, the Commission stated that forecasts are best developed from "an assumed zero-base, which seeks to reassess resources and costs required to fulfill its statutory duties on an annual basis."[479] However, Decision 2013-358 did not contain a direction to ATCO Electric to develop its future GTA forecasts using a "zero-based approach."

754. ATCO Electric explained in the current application that it uses an "activity-based forecasting approach," which it describes as "a ground-up assessment of the activities required and worked through with staff and managers responsible for executing the budgets."[480] These forecasts are initially prepared by relying on past experience and analysis of data from previous projects.[481] In its application, ATCO Electric indicated that its capital forecast is informed by various factors, including the AESO's Long-Term Transmission Plan, discussions with the AESO and customers, ATCO Electric's own forecasts for timing of events and the need for capital maintenance due to aging existing infrastructure and growth within its service area.[482] ATCO Electric indicated that any recognized opportunities for efficiency gains would be included in the forecasts developed for the entire test period and that additional savings realized in the current test period will be reflected in future forecasts so that any savings will "flow through to customers in future test periods."[483]

755. FTI analyzed ATCO Electric's staffing levels for capital projects in Section IV of the FTI evidence. FTI stated that ATCO Electric had certain obligations, as set out in Decision 2013-358, to justify the revenue requirement, including its number of forecast FTEs. In FTI's submission, ATCO Electric did not adequately support its requested revenue requirement in this regard because it did not prepare its FTE forecasts using a zero-based methodology.

756. FTI defined a zero-base forecast as being one derived from detailed staffing plans that reflect individual project needs, technical skills and functional competencies required and the resources available, including "their core competencies, current and expected utilization and known effectiveness working in similar positions."[484]

757. Between the original application and the updated application submitted on December 16, 2015, ATCO Electric's capital FTEs forecast for 2015 decreased from 957.0 to 938.2, and O&M FTEs for 2015 decreased from 288.7 to 243.3.[485] [486] In the RPG's view, this change indicates that the activity-based forecasting method used by ATCO Electric is unreliable. The RPG argued that if the activity-based budgeting was consistent with zero-based budgeting, there would not be significant changes to the forecasts throughout the proceeding.[487]

758. ATCO Electric stated that prevailing economic conditions and the associated impacts on direct assigned projects drove changes in the forecasts, which were updated throughout the

[479] Decision 2013-358, paragraph 163.
[480] Transcript, Volume 2, pages 332 and 312.
[481] Transcript, Volume 3, page 388.
[482] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 134.
[483] Transcript, Volume 10, pages 1727 and 1758.
[484] Exhibit 20272-X0784, FTI evidence, PDF pages 45-46.
[485] Exhibit 20272-X0004, application, schedules 5-5 and 25-5. Does not include A&G FTEs.
[486] Exhibit 20272-X0702, updated application, schedules 5-5 and 25-5 Does not include A&G FTEs.
[487] Exhibit 20272-X1297, RPG argument, PDF pages 76-77.

proceeding using the best available information.[488] The RPG, however, took the view that in preparing its forecasts, ATCO Electric should have expected that some direct assigned projects would be delayed as a result of economic conditions and that these impacts should have been reflected in the originally filed forecasts.[489]

759. Accordingly, the RPG requested that ATCO Electric be directed to "develop its forecast for capital FTEs on a zero-based project-by-project basis and file the requested support and implement key improvements to the reporting and tracking of capital FTEs for the next GTA."[490] It went on to argue that "[this] work should be performed by an independent expert reporting directly to the Commission." Alternatively, the RPG proposed that ATCO Electric could perform its own zero-based budgeting provided that interveners and the Commission were provided access to detailed information supporting the zero-based budgeting exercise and permitted to interview staff, as necessary.[491]

760. FTI submitted evidence on the reasonableness of ATCO Electric's project management costs on direct assigned capital projects as part of its evidence on zero-based budgeting for capital FTEs. FTI reviewed industry studies, standards and benchmarking data on project management and construction management (PMCM) to evaluate ATCO Electric's forecast costs for PMCM on direct assigned projects for the test period. FTI stated that, generally, organizations attempt to maximize return on investment in PMCM human resources. FTI proposed that a reasonable PMCM percentage cap can be determined by evaluating the ratio of capital expenditure labour costs to capital expenditure costs and comparing to industry studies.

761. The studies referenced by FTI show that as a company becomes more mature, its percentage of PMCM costs to project costs should decrease.[492] FTI indicated that while project complexity and increasingly conservative approaches to project design will affect certain aspects of project execution, the trend of an improving project management cost ratio should not be affected.[493] FTI assessed ATCO Electric at the highest maturity level using the project management maturity characteristics identified in one model. The FTI witness, Mr. Tusa, explained that ATCO Electric has the tools to be ranked at the highest level for project management maturity, however, there is still room to improve those tools beyond the current level.[494] FTI stated that, at ATCO Electric's maturity level, project management spend should be six to 10 per cent of capital expenditures. FTI asserted that ATCO Electric has not adjusted its capital FTEs to a level that would maintain a consistent pattern of capital expenditure labour percentage and that this results in underutilization of capital-related labour resources and overstaffing.

762. Accordingly, FTI recommended reductions to capital labour forecasts of $69.9 million in 2015, $41.0 million in 2016 and $33.1 million in 2017 based on a ratio of PMCM costs to total project costs of 15 per cent,[495] consistent with industry studies and benchmarking data.[496] These

488 Transcript, Volume 3, pages 370-371.
489 Exhibit 20272-X1297, RPG argument, PDF page 77.
490 Exhibit 20272-X1297, RPG argument, PDF page 17.
491 Exhibit 20272-X1297, RPG argument, PDF page 78.
492 Exhibit 20272-X0784, FTI evidence, PDF pages 48-50.
493 Exhibit 20272-X0819, CCA-AUC-2016FEB01-030(b), PDF page 30.
494 Exhibit 20272-X1279, RPG argument, PDF page 101.
495 Exhibit 20272-X0819, IR CCA-AUC-2016FEB01-032(c) in: 15 per cent was determined from an acceptable PMCM percentage of 10 per cent plus five per cent for engineering costs included in facility costs.
496 Exhibit 20272-X0784, FTI evidence, PDF pages 51-63.

amounts do not include an analysis for the HRTD and EATL projects or FTEs associated with the line construction crew as these were removed to normalize the data, consistent with ATCO Electric's methodology.[497] [498]

763. In rebuttal, ATCO Electric stated that the relationship between capital expenditures and FTE labour costs varies year-by-year and depends on a number of different factors. The result is that the relationship will not be consistent across different periods with different types of work. Year-to-year comparisons are also affected by level of utilization of contractors. ATCO Electric noted that its use of external contractors has decreased since 2012. In the test period, projects have been forecast to utilize internal resources for engineering and construction management. ATCO Electric also stated that, typically, projects to be completed at existing facilities require additional resources for planning, design and execution compared to greenfield projects of similar value. Finally, certain functional groups of capital FTEs do not have a linear relationship to capital expenditures. For example, accounts payable labour costs are driven by the quantity and type of invoices, not the dollar value of those invoices.

764. ATCO Electric stated that the industry studies and benchmark data used in the FTI evidence are an "apples-to-oranges comparison" to ATCO Electric's PMCM costs.[499] The utility reiterated that its labour forecasts are based on the actual work that needs to be executed, not on a percentage of the capital expenditures derived from benchmark data. ATCO Electric cautioned that if internal labour was reduced, additional contractors would be required to complete its project work.[500]

765. Mr. Tusa recognized that, should there be reductions to internal capital labour, this may be offset by increased use of contractors. However, he indicated that the only way to know if additional resources are required is to start with a "portfolio" staffing plan so that resources can be coordinated between projects.[501]

766. In argument, the RPG suggested that ATCO Electric's reorganization and FTE reductions indicates improper forecasting because ATCO Electric knew or ought to have known that it was over-staffed in 2015 in light of the observed reduction in capital work. The RPG continued to recommend the reductions proposed in the FTI evidence for capital labour, as well as changes to the MFRs for future GTAs.[502]

767. In reply argument, ATCO Electric stated that its capital labour resources include FTEs which are not specifically allocated to direct assigned capital and, therefore, the amounts related to the 15 per cent cap proposed by FTI for capital labour for PMCM costs are overstated. ATCO Electric also noted that the Commission rejected a similar proposal by the RPG for a reduction to AltaLink's engineering, procurement, construction management percentage in its GTA[503] and argued that the RPG's recommendation in this proceeding is unsupported by evidence, based on

[497] In AET-AUC-2015JUN08-018(d) Attachment, ATCO Electric provided an analysis of capital FTEs and capital expenditures. EATL and HRTD, ATCO Electric's two largest projects, were removed to provide a consistent calculation of capital expenditure spend per FTE employed.
[498] Exhibit 20272-X0819, CCA-AUC-2016FEB01-030(a), PDF page 29.
[499] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 27.
[500] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 23-27.
[501] Transcript, Volume 13, pages 2434-2435.
[502] Exhibit 20272-X1297, RPG argument, PDF pages 163-164.
[503] Decision 3524-D01-2016, paragraphs 557-575 and 582.

erroneous assumptions and similarly must be rejected.[504] Finally, ATCO Electric argued that the RPG's recommendations for new MFRs for direct assigned capital forecasts are not warranted and no support was provided to show that the effort required to implement those recommendations would result in tangible benefits.[505]

Commission findings

768. The Commission held in Decision 2013-358 that "ATCO Electric would be best to develop its forecasts from an assumed zero-base, which seeks to reassess the resources and costs required to fulfill its statutory duties on an annual basis, without assuming that costs are simply incremental to the actual or forecast costs of the preceding year."[506] The Commission considers that the activity-based forecasting approach employed by ATCO Electric is consistent with the Commission's findings in this regard.

769. In Decision 3539-D01-2015,[507] the Commission accepted EPCOR Distribution & Transmission Inc.'s approach to capital maintenance project forecasting and O&M forecasting, which was described as a "bottom-up approach" where each project or activity's cost is developed based on the work required for that particular project or activity and is not related to previous years' forecasts.[508] The Commission considers that this methodology is similar to the activity-based approach used by ATCO Electric.

770. The Commission is satisfied that the activity-based forecasting methodology employed by ATCO Electric is reasonable insofar as it incorporates a bottom-up approach to forecast cost determinations and does not simply involve the inflation of past actuals. Consequently, the Commission finds that there is currently no need to direct ATCO Electric to employ a prescribed zero-based budgeting methodology in creating its GTA forecasts.

771. The Commission further finds that ATCO Electric's activity-based approach for preparing capital labour expenditure forecasts is acceptable for the purposes of forecasting capital expenditures to determine revenue requirements in the test years. Consequently, FTI's request for capital labour expenditure disallowances related to PMCM is denied.

772. Regarding the RPG's recommendations with respect to MFRs, the Commission notes that it has previously provided ATCO Electric with direction[509] as to what information is considered relevant and necessary for the purposes of examining capital within a GTA. These information requirements supplement the mandatory MFR found on the Commission's website.[510]

773. In Decision 2013-358, the Commission confirmed that it considered that a change to the MFR was not required to ensure that it was provided with adequate information upon which to assess capital project costs, generally:

504 Exhibit 20272-X1309, ATCO Electric reply argument, PDF page 98.
505 Exhibit 20272-X1309, ATCO Electric reply argument, PDF page 101.
506 Decision 2013-358, paragraph 163.
507 Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015.
508 Decision 3539-D01-2015, paragraphs 79, 113 and 527.
509 For example, paragraphs 1093-1094 and 1096 in Decision 2013-358 discuss additional information which would be beneficial for ATCO Electric to provide in future GTAs.
510 Minimum Filing Requirements – Phase I, May 8, 2006.

> While the Commission finds that the additional information directed previously should be included in GTAs, it is not prepared to revise the MFR to make the provision mandatory for all transmission utilities. The MFR is in place not only for ATCO Electric, but for all the other transmission utilities, and it may not be necessary for the other transmission utilities to provide the level of detail requested by the RPG with respect to capital project costs, especially if the level of capital project activity for these other transmission utilities is not significant. Consequently any proposed changes to the MFR should be examined through a separate process, in which all interested parties would be able to participate. The Commission therefore rejects the submission of the RPG that the information it has requested be made part of the MFR.[511]

774. The Commission is not persuaded that it should reconsider its previous determinations in in this regard. Accordingly, the RPG's request for modification of the existing MFR is denied.

11.1.4 Risk management processes

775. ATCO Electric stated that it "applies a consistent, process-driven approach to the project management of all capital projects." This process includes continual improvement of processes as required and applies learnings from existing projects and regulatory changes.[512] ATCO Electric also noted that it continues to implement and improve its project delivery framework, which is based on the Project Management Body of Knowledge (PMBOK).[513] It calls this framework its Transmission Project Execution Model (TPEM). The framework is a suite of methodologies and processes which focus project efforts and provide consistency in project deliverables in key areas such as project management; procurement, contract administration and material management; construction management; and project risk management.[514] ATCO Electric's processes and desired outcomes in each of these areas were described in the application.[515] In addition, ATCO Electric provided its project risk management planning guide which specifies the procedures used to perform risk management activities for a transmission project, including risk planning, identifying risks, performing qualitative risk analysis, developing risk responses, monitoring and controlling risks, preparing a risk register, performing a contingency analysis and preparing a document of assumptions.[516] In response to an undertaking, ATCO Electric further provided its transmission asset risk management process document and transmission impact classification document which pertain to risk management on capital maintenance projects.[517]

776. In reference to capital maintenance projects, ATCO Electric provided its risk analysis process to quantify risks and prioritize work. ATCO Electric also performs a risk analysis for forecasting of direct assigned capital projects which has a similar process. ATCO Electric defines risk as the effect of uncertainty on objectives. Risk is expressed in terms of a combination of the materiality/impact of an event and the associated probability or likelihood of occurrence.[518] Probability and materiality are quantified on discrete scales where a lower number

[511] Decision 2013-358, paragraph 1095.
[512] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 136.
[513] The Project Management Body of Knowledge is a set of widely accepted standard terminology and guidelines for project management which has been prepared by the Project Management Institute.
[514] Exhibit 20272-X1099, revised application narrative – blackline, PDF pages 165-166.
[515] Exhibit 20272-X1099, revised application narrative – blackline, PDF pages 166-181.
[516] Exhibit 20272-X1120, ATCO Electric rebuttal, FTI evidence Attachment 6, PDF pages 237-261.
[517] Exhibit 20272-X1179.
[518] Per ATCO Electric's response to AET-CCA-2015JUN08-074(a) in Exhibit 20272-X0345 and in testimony in Transcript,Volume 5 at page 726, probability is the likelihood of a risk occurring over the life of the project and materiality is how significantly a specific risk could impact the project.

is a lower probability or materiality. The product of both values provides a risk factor which quantifies the level of risk.[519] The project-specific probability and materiality for direct assigned projects are determined using established criteria.[520] Probability for capital maintenance projects is determined on the basis of available information on the condition of the assets and the likelihood of the performance of that asset being affected. The underlying assumptions for the probability ranking are outlined in the business cases.[521]

777. The elements in the risk register are identified and developed by the project team and project manager. Identified risks and mitigation strategies are updated or added to the risk register throughout the project. ATCO Electric stated that when a material cost variance arises, the associated risk is updated in the risk register and the corresponding change in allocated contingency is accounted for and reported in the monthly final forecast cost. Should it be required, the change management process (submission of a change proposal) will be followed on those cost variances.[522]

778. ATCO Electric argued that it has continued to improve its forecasting and project delivery framework. This framework provides "coordinated and standardized project management processes for scheduling, costing, change management, communications management, trend management, risk management, and project reporting."[523] ATCO Electric confirmed that the processes included in this framework (i.e., engineering and project management), are typically done in-house, not by contractor.[524]

779. FTI submitted evidence on the adequacy of ATCO Electric's risk register and decision matrix and on the reasonableness of the contingency estimates developed using a risk based approach, which were developed in response to Commission directions 5 and 6 from Decision 2014-283. Each of these issues will be addressed separately in the subsections below.

780. Mr. Retnanandan, on behalf of the CCA, also submitted evidence on ATCO Electric's approach to project risk management. In his evidence, Mr. Retnanandan submitted that the information provided by ATCO Electric on its risk management systems is useful, however, further refinements could be made so parties could follow "the thread of events and internal decision making from a risk event, through the various decision points, to the reported cost variance." In his view, this would provide insights into the effectiveness of the underlying risk management system and help the Commission assess prudence for direct assigned capital projects. The following refinements were broadly recommended for ATCO Electric's risk management system: a documented risk management strategy which is project specific, a comprehensive risk register, documentation of details related to risk responses for each risk event, documentation of details of change control procedures and identification and descriptions of impacts triggered by risk events and the risk response.[525]

[519] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 160.
[520] Exhibit 20272-X0345, AET-CCA-2015JUN08-072(b) Attachment 12, Appendix I – criterion for determining qualitative ratings of probability and materiality, PDF page 80.
[521] Transcript, Volume 5, pages 762-763.
[522] Exhibit 20272-X0348, AET-CCA-2015JUN08-020(c), PDF page 60.
[523] Exhibit 20272-X1298, ATCO Electric argument, PDF page 127.
[524] Transcript, Volume 7, page 1195.
[525] Exhibit 20272-X0785, CCA evidence of Raj Retnanandan, PDF pages 5-7.

781. ATCO Electric did not address this evidence in its rebuttal[526] nor was it addressed in any parties' argument or reply.

Commission findings

782. Findings related to specific components of ATCO Electric's risk management processes are addressed in the relevant subsections below.

783. As established in the 2015-2016 AltaLink GTA decision, an examination of a TFO's risk management practices is relevant to a GTA proceeding:

> 632. Therefore, the Commission accepts the notion that an examination of risk management practices is beneficial. From a direct assign perspective, it is the Commission's view that any assessment of the prudence of such expenditures, including consideration of AltaLink's risk management practices, are a DACDA matter. The examination of risk management practices pertaining to capital replacements and upgrades or for other capital projects, are rightfully considered in a GTA proceeding.[527]

784. In Decision 2014-283, the Commission found that ATCO Electric had adequate project and construction management processes in place.[528] The evidence on the record of this proceeding is that ATCO Electric continues to refine and improve those processes in response to changes in industry practices and its own experiences. Additionally, ATCO Electric has implemented changes to its project management tools as directed by the Commission. The evidence in this proceeding further reveals that ATCO Electric employs detailed reporting and recording of ongoing project activity and risks in real time. The Commission has reviewed the evidence on ATCO Electric's project delivery framework and is satisfied that the project delivery framework meets industry standards for the consistent management and execution of projects, with continuous improvement in project delivery processes and methodologies, and deliverables that can be used to support project expenditures in regulatory applications.

785. The Commission finds no reason to direct further modifications to ATCO Electric's risk management processes at this time.

11.1.4.1 Risk register

786. In Decision 2014-283, the Commission directed ATCO Electric to provide an update of its review of its risk registry practices in its next GTA application. ATCO Electric's response is found in that section of its current application describing its risk registry practices.[529] ATCO Electric stated that it prepares baseline risk registers at the PPS estimate stage.[530] The risk assessment that is performed at that stage is based on common risks and then is "fine-tuned" for project-specific risks, using site-specific data where possible.[531] [532] ATCO Electric's project

[526] Exhibit 20272-X1120, ATCO Electric rebuttal.
[527] Decision 3524-D01-2016, paragraph 632.
[528] Decision 2011-283: FortisAlberta Inc. Review and Variance of Decision 2010-039, Proceeding 1012, Applications 1606824-1, 16071731, June 28, 2011, paragraph 425.
[529] Exhibit 20272-X0002, application, PDF page 282.
[530] Exhibit 20272-X0345, AET-CCA-2015JUN08-074(a), PDF page 103.
[531] Exhibit 20272-X0002, application, PDF page 172.
[532] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 179.

management plans include a section on the strategy to manage the risk register for the duration of the project which generally describes when the risk register is to be reviewed and updated.[533]

787. The risk register contains the following fields: risk description, trigger event(s) and root cause(s), risk impact, probability and materiality assessment, risk score and mitigation and action plan.[534] These fields and the development of the risk register were further described in the section above. The risk register, as it specifically relates to contingency estimates, is further described in Section 11.1.4.3 below.

788. The risk register is developed by the project team which, on larger projects, may include a risk analyst. The role of the risk analyst is performed by the project manager on smaller projects. The risk register is circulated internally before it is released to provide executives the opportunity to ask questions. Ownership of the risk register remains with the project team.[535]

789. FTI analyzed the risk registers placed on the record by ATCO Electric and ATCO Electric's responses to IRs related to risk registers and its risk management processes. FTI evaluated ATCO Electric's TPEM and risk registers to the PMBOK standard and concluded that while the risk register and risk management system incorporate elements of the PMBOK, significant processes are still missing.

790. FTI determined that ATCO Electric's risk registers were deficient in the following ways:

- They do not include any quantitative analysis to permit ATCO Electric to adjust estimates and forecasts for financial and scheduling uncertainties associated with identified risks.
- They are static documents prepared at the outset of the project but are not updated throughout the project's lifecycle to add newly identified risks or to reallocate/release contingencies for risks not realized.
- Historical data should be used to score and quantify risks, and identify effective treatment and mitigation practices.
- Risk identification does not incorporate the following techniques recommended by PMBOK: interview of stakeholders/team members/subject matter experts, root cause analysis, brainstorming and a mathematical technique to reduce biases.
- They do not include an alternative course of action should a risk be realized (despite mitigation strategies).
- There is no central management system for risk registers which can result in data entry errors and inconsistent treatment of risks.
- They do not include opportunities with a positive impact on the project outcome.[536]

791. ATCO Electric rebutted each of FTI's points:

- The qualitative risk management identifies high and extreme risks and determines the appropriate mitigation strategies and contingency amounts. These risks are monitored throughout the project. This is a reasonable and cost-effective approach.

[533] For example, the project management plan for the Bourque-Bonnyville project was provided in response to IR AET-CCA-2015JUN08-090 Attachment 2 in Exhibit 20272-X0345 at PDF page 598.
[534] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 179.
[535] Transcript, Volume 5, pages 721-722.
[536] Exhibit 20272-X784, FTI evidence, PDF pages 11-18.

- Risk registers are updated on a regular basis in consultation with the project team subject matter experts.
- ATCO Electric does quantify the impact of risks on project costs, schedule variances, operability metrics, HSE, scope, methodology and reputation, as shown in the risk registers.[537]
- The risk management program focuses on identifying the most likely risk response/mitigation plans for high and extreme risks. Each risk gets reviewed and updated periodically by the project team as circumstances warrant.
- Risk registers are developed from a generic risk register which is periodically reviewed and updated to include probable risks on transmission projects. A database is currently being investigated to improve consistency and support future risk registers with comparable historical project information.
- The risk management process does identify opportunities that could have a potential positive impact and tracks them in the risk register.[538]

792. In argument, the RPG recommended that the Commission direct ATCO Electric to "adopt recommended improvements to its risk register and risk management framework and that risk registers should be provided for DA projects greater than $5 million." The RPG submitted that FTI's recommendations are relevant in a GTA since they can take months to fully implement and the recommendations are proactive – waiting until a deferral account proceeding is reactive and misses the opportunity for improvements.[539]

793. ATCO Electric argued that it had complied with the Commission's direction and noted that the direction did not prescribe how ATCO Electric was to conduct its review of risk registry practices. ATCO Electric also argued that the evidence from FTI was inconsistent in its positions, making numerous recommendations for additional processes or steps that ATCO Electric should implement but acknowledging that ATCO Electric has a high risk management maturity.

794. ATCO Electric likened FTI's recommendations to "usurping the role of utility management in running the day-to-day operations of the utility" and submitted that the recommendations are outside the purpose of a GTA and that the recommendations "extend beyond what is reasonably necessary to test just and reasonable rates." Accordingly, ATCO Electric requested that the Commission reject FTI's recommendations regarding ATCO Electric's risk management practices.[540]

795. In reply argument, the RPG clarified that while the FTI witness stated that ATCO Electric had the tools to be ranked at the highest level of project management maturity, there is still room for improvement. The RPG also submitted that it is not trying to manage ATCO Electric, but rather is providing recommendations to assist ATCO Electric's management in "properly managing their utility." It explained that implementation of its recommendations would avoid a future debate on whether or not ATCO Electric properly executed its direct

[537] ATCO Electric referred to exhibits 20272-X0381 and 20272-X0386.
[538] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 41-46.
[539] Exhibit 20272-X1297, RPG argument, PDF page 164.
[540] Exhibit 20272-X1298, ATCO Electric argument, PDF pages 128-130.

assigned capital projects. The RPG stated that the onus is on ATCO Electric to demonstrate that its direct assigned capital costs are not inflated due to its capital project management processes.[541]

796. In reply argument, ATCO Electric stated that "[t]he RPG's recommendations, if adopted, would bring significant additional burden and expense" but the benefits of those recommendations have not been identified.[542]

11.1.4.2 Decision matrix

797. In Decision 2014-283, the Commission directed ATCO Electric to provide an update on developing a decision matrix for projects to document key decisions. In its response, ATCO Electric provided a decision matrix template and stated that the matrix will be implemented in 2015 for projects going forward. Key decisions will be summarized on a project-by-project basis and will be included in future deferral applications. The decision matrix template includes the following categories for key planning and execution project decisions: substation siting; transmission line routing and telecommunications tower siting; transmission line tower type and conductor sizing; contracting strategy; foundation selection; delayed start of line construction; and early spring break up.[543] The decision matrix would incorporate all major design, contracting, and scheduling decisions which result in cost increases and/or schedule delays. The decision matrix was developed using ATCO Electric's past experience as well as the directions in the Commission findings in Decision 2014-283.[544]

798. ATCO Electric stated that the purpose of a decision matrix is to identify key decisions that need to be made during each phase of a project.[545]

799. FTI analyzed the proposed decision matrix and concluded that it captures only a minimal amount of information and there is no clear explanation of how it would be used. FTI submitted that the categories of key decisions listed in the decision matrix template were insufficient. In its view, the proposed decision matrix is missing key information such as the purpose, scope, methodology, timelines, alternatives and cost/benefit analysis associated with identified alternatives.

800. In asserting that ATCO Electric's proposed decision matrix is deficient, FTI outlined what, in its view, is generally required of a decision matrix:

- It should be an interactive tool that assists with planning and executing a project.
- It should integrate with the execution plan, risk register, risk management plan and project controls.
- It should be reported monthly.
- It should be updated in real time and use risk weighted calculations to quantify the cost/benefit analysis of alternatives.
- It may be supported by additional documentation such as decision trees, net present value evaluations and sensitivity analyses.
- It should include the following fields: date of event, required date of decision, project area/category, decision maker and authority, decision description, cross-references to

[541] Exhibit 20272-X1307, RPG reply argument, PDF pages 101-102.
[542] Exhibit 20272-X1309, ATCO Electric reply argument, PDF page 101.
[543] Exhibit 20272-X0002, application, PDF pages 282-283.
[544] Exhibit 20272-X0349, AET-CCA-2015JUN08-010(c) and (e), PDF page 1299.
[545] Exhibit 20272-X0349, AET-CCA-2015JUN08-010(f), PDF page 1300.

appropriate logs (such as change logs, risk register, contingency log, etc.), alternatives considered, chosen course, outcome, parties notified, related source documents, related backup analyses and cost/benefit calculations.[546]

801. In rebuttal evidence, ATCO Electric stated that it has the controls in place to provide the elements necessary for the Commission to determine prudence and that it already documents key decisions in different documents which are filed in support of its decisions. ATCO Electric submitted that it has standardized processes for decision making throughout the organization which are more in line with the nature of its business and projects undertaken. It confirmed that decisions are taken in alignment with the AESO connection process, which is intended to lead to the lowest possible transmission capital expenditures, and that procurement decisions are tested through AESO compliance audits. ATCO Electric cautioned that implementing a decision matrix as described by FTI would be administratively burdensome and would bring no further value to ratepayers.[547]

802. In oral testimony, Mr. Vachon, ATCO Electric's witness, stated that, with hindsight, the decision matrix developed by the utility does not produce additional value because the decisions taken throughout the project are either already documented and available or can otherwise be easily produced. For example, technical options are documented in the connection study, line optimization and/or engineering study report; facility applications document the routing and siting decisions; change proposals document decisions related to cost changes; and procurement decisions are tested in compliance audits. Mr. Vachon also confirmed that ATCO Electric is currently not using the decision matrix it proposed.[548]

803. In argument, the RPG agreed that the decision matrix proposed by ATCO Electric has limited value and recommended that the Commission direct ATCO Electric to adopt FTI's recommended improvements to the proposed decision matrix and begin utilizing the recommended matrix immediately. The RPG also requested that the Commission provide further direction regarding the definition, requirements and specific applications of the key decision matrix. In its view, this would limit the volume of evidence filed in future applications.[549]

804. In argument, ATCO Electric reiterated that the decision matrix detail set out in the FTI evidence would duplicate the information already included in records that ATCO Electric files in support of direct assigned project expenditures. ATCO Electric requested that the Commission decline to direct ATCO Electric to implement FTI's recommendations for decision matrices.[550]

805. In reply argument, ATCO Electric reiterated that "[t]he RPG's recommendations, if adopted, would bring significant additional burden and expense" but the benefits of those recommendations have not been identified.[551]

11.1.4.3 Contingency calculated using a risk register approach

806. In oral testimony, Mr. Vachon, ATCO Electric's witness, stated that the contingency estimate is the money to cover uncertainties or risk events that may or may not occur on a

[546] Exhibit 20272-X0784, FTI evidence, PDF pages 18-23.
[547] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 46-47.
[548] Transcript, Volume 6, pages 1025-1028 and 1033-1034.
[549] Exhibit 20272-X1297, RPG argument, PDF pages 166-168.
[550] Exhibit 20272-X1298, ATCO Electric argument, PDF page 130-131.
[551] Exhibit 20272-X1309, ATCO Electric reply argument, PDF page 101.

project.[552] Examples of risk events that may be addressed through contingency estimates include: delayed, missing or damaged material; a change from the PPS estimate of the type and mix of foundations (because geotechnical conditions differed from those assumed); external stakeholder consultation commitments; outage coordination; scope changes; site access constraints and poor access road conditions; weather conditions; and hearing costs.[553] As Mr. Vachon acknowledged in the hearing, these risk events are outside the control of the company and can have consequences on the actual project costs:

> Q. There are different ways to manage a project schedule, sir, but schedule is impacted by things like the weather, which is absolutely outside the control of ATCO Electric Transmission; correct?
>
> A. MR. VACHON: We do not control the weather, that's correct.
>
> Q. And so forecasting the weather is, at best, a guess over the life of the project from the PPS stage?
>
> A. MR. VACHON: We look at previous seasons and seasonalities in our assessment, but on a day-to-day basis, we cannot predict the weather.
>
> Q. And frequently the schedule of a major capital project or, indeed, even a minor capital project is materially impacted by events like the weather or events such as the coordination of trades and contractors, material supply and the like. Isn't that fair, sir?
>
> A. MR. VACHON: There are different things that can impact a project schedule, if that's your question.
>
> Q. And impacts to projects' schedule may have material consequences on the company. They can be extreme consequences, depending on the circumstances, or they can be fairly minor consequences, depending, again, on the individual circumstances. Isn't that fair?
>
> A. MR. VACHON: Hypothetically, yes.[554]

807. Mr. Madsen, a witness for the CCA, agreed that these risk events are outside the control of the company but contended that ATCO Electric should be expected to have some knowledge of the risks, or challenges, that might be faced and include expected costs related to those challenges in the forecast.[555]

808. In Decision 2014-283, the Commission directed ATCO Electric to calculate contingency on a go-forward basis for projects using a risk register approach. This direction arose due to concerns with ATCO Electric's previous approach of simply calculating contingency as 10 per cent of its total project estimate.[556]

809. ATCO Electric responded to this direction in the application stating that it "has implemented, on a go-forward basis, contingency allowances based on an express risk register-based approach to determine contingency allowance amounts for all direct assigned projects

[552] Transcript, Volume 5, page 723.
[553] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 228.
[554] Transcript, Volume 5, pages 735-736.
[555] Transcript, Volume 13, pages 2304-2306.
[556] Decision 2014-283, paragraphs 121 and 124.

currently underway."[557] It explained that a contingency amount is determined for each key risk, based on the probability and materiality established by the project team for that risk,[558] and the sum of contingency values for all key risks is used to determine the total project contingency. This is evaluated as a percentage of the total base cost estimate to confirm reasonableness.[559] The determined contingency is also compared to similar projects to confirm that it aligns with ATCO Electric's historical experience.[560] In testimony, Mr. Vachon clarified that all risks are assessed but contingency is only allocated to the most significant risks.[561]

810. In response to an IR, ATCO Electric provided the risk registers for seven projects, of which three had contingency estimates assigned to line items in the risk registers, to demonstrate compliance with this direction. These projects were in the construction phase at the time of the IR response.[562]

811. ATCO Electric stated that contingency analysis is built into the scoping, documentation of assumptions and estimating functions of its project delivery framework. The analysis determines appropriate contingency amounts to be applied to certain defined risk events, as well as appropriate schedule adjustments to support risk mitigation strategies. The contingency is either drawn down to address realized risks or can be reallocated or released.[563] A change proposal is submitted to the AESO for the release of contingency funds when the amount reaches the materiality threshold for change proposals.

812. ATCO Electric confirmed in testimony that the current forecasts in this application reflect the latest updates in contingency amounts.[564]

813. FTI analyzed the sufficiency of both ATCO Electric's use of a risk register-based approach to determine project contingencies and the contingency in its forecasts of capital expenditures for a sample of direct assigned system projects.

814. FTI submitted that if ATCO Electric was able to implement the risk register approach to contingency estimates on three projects, it should have implemented them on all 13 direct assigned projects having forecast costs of greater than $5 million.[565] FTI also pointed out that the Commission's direction regarding the use of risk registers for contingency calculation was not specific to the size of the project and, therefore, ATCO Electric should be required to implement the risk register approach to contingency calculation on all of its projects. FTI noted, in this regard, that ATCO Electric had not provided any evidence to demonstrate that it has implemented the risk register-based approach to estimating contingency on smaller projects. Nor had ATCO Electric provided any evidence to show that it updates its risk registers regularly to manage and allocate contingency amounts. In FTI's view, ATCO Electric's valuation of project

557 Exhibit 20272-X0002, application, PDF page 284.
558 Transcript, Volume 5, page 725.
559 Exhibit 20272-X0345, AET-CCA-2015JUN03-073(b), PDF page 99.
560 Transcript, Volume 5, page 745.
561 Transcript, Volume 5, page 752.
562 Exhibit 20272-X0345, AET-CCA-2015JUN08-074(a) response and attachments, PDF pages 103 and 106-200.
563 Exhibit 20272-X1099, revised application narrative – blackline, PDF page 180.
564 Transcript, Volume 7, page 1121.
565 The remaining projects, which did not use a risk-register approach to estimate contingency, were: 53603 – Little Smoky South to Wembley 240-kV Line, 53605 – Wesley Creek to Little Smoky South 240-kV Line, 54904 – Jasper Transmission Interconnection, 55126 – Ells 9L76/9L08 240-kV DC Line, 55737 – Thickwood Development, 56763 – New 9LX01 (Substation F-Tinchebray), 57155 – Cold Lake Area - Bourque Bonnyville, 58001 – Edmonton – Calgary 500-kV East Route, and 58510 – 9L84/69 Second Side Stringing.

contingencies is not determined by quantifying specific risks and its process is subjective and "lacking empirical rigor."[566]

815. FTI stated that the draw down or release of contingency amounts as risks are overcome or fail to materialize is a core issue in contingency management. FTI analyzed specific projects and how contingency was determined and drawn down and found some data to be unclear. Based on its analysis, FTI concluded that as of April 30, 2015, $3.86 million in contingencies included in project forecasts in this application were not likely to be spent.[567]

816. FTI recommended that the Commission direct ATCO Electric to:

- Provide updated documentation regarding the status of contingencies for all ongoing projects.
- Produce and submit risk registers for all direct assigned system projects greater than $5 million.
- Estimate project contingencies using quantitative methods.
- Update its identification and assessment of project risks regularly and document updates in the risk registers.
- Provide the AESO monthly reports for direct assigned projects greater than $5 million in future proceedings.[568]

817. In rebuttal, ATCO Electric noted that baseline risk registers are established prior to the PPS submission and for projects developed prior to 2012, contingency was not assigned to line items in the risk registers. ATCO Electric also provided the status of contingency allowances for the 13 direct assigned projects identified by FTI. Five of those projects are in early stages and the PPS has not been submitted but ATCO Electric confirmed that contingency will be assigned to risks and included in the PPS. Four projects have been energized so the contingency has been reduced to $0. One project has been cancelled and the remaining projects do not have contingency assigned to risks because the process was not developed at the time the PPS submission was being prepared. ATCO Electric further noted that an updated PPS template was developed in 2015 in collaboration with the AESO. That template includes risks to which contingency will be applied and is being used on all direct assigned projects in which contingency is allocated to risks. Quantitative methods based on probability and cost impact are applied to estimate project contingency in the newly developed PPS template.

818. ATCO Electric also stated that it has a process in place to update and manage risk registers and allocate contingency amounts, as demonstrated in the updated PPS template and in the change proposals issued to the AESO.[569]

819. In testimony, ATCO Electric's witness also stated that the contingency level tends to be "on the lower side in the opinion of the project team" in order to incent the team to find efficiencies.[570] The witness also noted that the company's risk register-based approach for contingency estimates had been evaluated in the Cost Oversight Management (COM) Pilot program and that the report produced by the COM Pilot for the Birchwood 240-kV Line project

[566] Exhibit 20272-X0784, FTI evidence, PDF pages 26-30.
[567] Exhibit 20272-X0784, FTI evidence, PDF pages 30-38.
[568] Exhibit 20272-X0784, FTI evidence, PDF pages 38-39.
[569] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 48-53.
[570] Transcript, Volume 5, page 759.

indicated that the approach used by ATCO Electric was adequate.[571] The COM report did suggest that the contingency should be higher in the NID estimate to account for uncertainty and larger risks. The ATCO Electric witness confirmed that this suggestion is under consideration.[572]

Commission findings

820. The Commission's direction in Decision 2014-283 regarding risk registers and decision matrices was not overly prescriptive. For example, it did not specifically prescribe a format to be used, or specific industry standards to follow in risk register or decision matrix development. It was expected that risk registers and decision matrices developed by ATCO Electric would meet the utility's needs and fit with its processes (existing and under development) while also meeting the Commission's need for greater clarity in project design and decision making in order to evaluate prudence.

821. The Commission considers that clarification of its direction in Decision 2014-283 with respect to the development of decision matrices is required. ATCO Electric has stated that the matrix would identify key decisions that need to be made. In the Commission's view, a plain reading of its previous direction indicates that a suitable decision matrix would be a record of all key decisions that were made on a project. These would include decisions made throughout the life of the project, from planning and permitting through detailed design and construction, and culminating in testing and commissioning. This would create a record of all decisions that affected the project cost and schedule in one location, and permit the Commission to focus its review on those decisions which require additional documentation to support claims of prudency in a deferral account application. An acceptable decision matrix is also required to record the justification, including options considered to address the issue, and the outcome of a given decision. The Commission considers that this tool should be used together with the risk register to record what risks did or did not occur, the solutions proposed, the decision made to avoid, mitigate or accept the risk and the resulting impact. The information and template provided in Attachment 2.19 to the application appear to be consistent with the creation of a decision matrix that would achieve these goals.

822. The Commission continues to be of the view that a risk register and decision matrix would assist both it and interveners in managing, and focusing on, the documentation necessary for testing future transmission project deferral account reconciliation applications.

823. The Commission has reviewed the evidence on the record with respect to the proposed risk register and decision matrix and is satisfied that these tools are generally consistent with industry standards and are adequate to track risks and key decisions throughout the project cycle. The Commission, accordingly, finds that ATCO Electric has complied with Direction 5 of Decision 2014-283 and finds no reason to direct further modifications to ATCO Electric's proposed risk register and decision matrix at this time. The Commission expects, however, that these tools will be continually refined by ATCO Electric to meet its needs and accommodate changing industry practices and experience.

824. The Commission has reviewed the evidence on the record with respect to ATCO Electric's implementation of a risk register-based approach to estimating contingency and finds that ATCO Electric has complied with the Commission's previous direction. The evidence shows that ATCO Electric has implemented this approach for a number of projects underway

[571] Transcript, Volume 5, pages 753-754.
[572] Transcript, Volume 7, page 1123.

and that it will use this approach for all direct assigned projects going forward. One example in this proceeding where ATCO Electric implemented the risk register-based approach to update the contingency estimate is the Jasper Interconnection project. The contingency amount included in the project forecast was $8.3 million in the initial application but was revised to $12.9 million in the February 23, 2016 update.[573] ATCO Electric's witness confirmed that this change was due to a risk analysis, whereas the contingency previously had been based on a parametric estimate.[574] The Commission finds no reason to direct modifications to ATCO Electric's risk register-based approach to contingency estimates.

825. ATCO Electric has included its latest contingency estimates in forecast project costs, therefore the Commission does not find it necessary to direct ATCO Electric to provide updated documentation regarding the status of contingencies for all projects that are ongoing.

826. The adequacy of project contingency estimates will continue to be evaluated on a project-by-project basis in future GTAs.

11.1.5 Adequacy of business cases

827. The adequacy of ATCO Electric's business cases was raised in evidence by the RPG[575] and addressed in argument by Calgary.[576] FTI submitted evidence on the sufficiency of information filed to support direct assigned capital projects.[577]

828. The RPG recommended that the Commission direct ATCO Electric to improve its asset risk assessment process and its capital maintenance business cases in order to provide a transparent and credible prioritization of capital maintenance projects justified on the basis of identified benefits. The RPG's recommendations regarding improvements to the capital maintenance business cases will be addressed further in Section 11.4.2.1 below.

829. In argument, Calgary submitted that ATCO Electric had not filed a proper business case to support the full implementation of its asset management program. It claimed that ATCO Electric's proposed approach to implement its asset management program did not provide for any independent, objective assurance that the program would be International Standards Organization (ISO) compliant and that IT projects, totaling $22.3 million, either outright lacked business cases to support them, or where business cases had been filed, were inadequate because they lacked cost-benefit analyses, including a measureable or quantified benefit.[578]

830. Calgary submitted that the absence or inadequacy of business cases were grounds for disallowing the IT related capital projects in excess of $500,000. It also urged that until ATCO Electric files a full, comprehensive and proper business case for asset management, the Commission disallow the costs of ATCO Electric's proposed asset management activities, as described in the current application.[579]

831. More generally, Calgary argued that the Commission should not approve requested utility costs unless those costs are supported by business cases that meet Commission requirements.

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573 Exhibit 20272-X1104, PDF page 62.
574 Transcript, Volume 9, page 1589.
575 Exhibit 20272-X0789, RPG main evidence, PDF pages 49-50.
576 Exhibit 20272-X1299.
577 Exhibit 20272-X0784, FTI evidence, PDF pages 39-42.
578 Exhibit 20272-X1299, Calgary redacted argument, paragraph 22, page 7
579 Exhibit 20272-X1299, Calgary redacted argument, paragraph 23, page 8.

832. Calgary noted that in Decision 3577-D01-2016[580] the Commission had considered the general principles previously established for capital project business cases and stated the following:

> 89. In addition to the requirements included in Rule 020,[[581]] 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**.[582] [emphasis added by Calgary]

833. In the same decision, the Commission expanded upon the four criteria previously established in Decision 2000-9[583] and Decision 2001-97[584] as follows:

> 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.[585] [emphasis added by Calgary]

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580 Decision 3577-D01-2016: ATCO Pipelines, 2015-2016 General Rate Application, Application 1611077-1, Proceeding 3577, February 29, 2016.
581 AUC Rule 020: *Rules Respecting Gas Utility Pipelines*.
582 Exhibit 20272-X1299, Calgary redacted argument, paragraph 66, pages 19-20.
583 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.
584 Decision 2001-97: ATCO Pipelines South, 2001/2002 General Rate Application Phases I and II, Application 2000365, File 1306-3, December 12, 2001. Errata to Decision 2001-97 issued January 15, 2002.
585 Exhibit 20272-X1299, Calgary redacted argument, paragraph 67, page 20.

834. Calgary argued that the Commission's clarification of its long standing principles for business cases applied equally to those filed by ATCO Electric in this proceeding. It submitted that a cost-benefit analysis is required and fundamental for and to the analysis and assessment of the alternatives considered, and to the selection of the preferred alternative. In addition, life cycle costing would be necessary to carry out the net present value of cost of service (NPVCOS) analysis as "an economic measure in order to assess the alternatives."[586]

835. Calgary submitted that none of ATCO Electric's business cases for IT projects and asset management included these "crucial and required elements." Calgary argued that these projects should not be approved by the Commission.[587]

836. Calgary claimed that the filed IT project business cases do not provide the incremental 10-year capital and operating costs of alternatives, the discount or investment rate, or the annual cost of alternatives for the period analyzed. Additionally, those business cases show no benefits or, alternatively, benefits that are attributed to safety considerations or capital growth, which Calgary argued are irrelevant considerations as drivers of IT expenditures because safety and growth have no bearing on ATCO Electric's ability to discharge its onus in this application.

837. ATCO Electric stated that it "disagrees with the City of Calgary's characterization of ATCO Electric's IT business cases, and submits that its forecast IT capital expenditures in the test period are reasonable and adequately supported" and "that if costs are necessary to ensure the safe and reliable operation of the transmission system, this is sound evidence that such costs are prudent."[588]

838. ATCO Electric acknowledged the applicability of the MFR found in the Bulletin 2006-25[589] Consensus Documents and approved in EUB Decision 2007-017[590] in setting out the information to be included in its 2015-2017 GTA. However, ATCO Electric disagreed with the characterization in Calgary's argument, stating:

> Calgary references Decisions 2000-9 and 2001-097 as setting out the "long standing principles" for business cases as being applicable to AET in the Proceeding (Ex. 1299, paragraphs 40-48). AET notes that these decisions predate the issuance of the MFR and while they may generally guide ATCO Pipelines business case requirements (as ATCO Pipelines is not required to follow the Bulletin 2006-25 MFR), it is the MFR that are relevant to AET's GTA in this Proceeding. Therefore, to the extent that Decisions 2000-09, 2001-097 or 3577-001-2016 impose business case requirements over and above, or that are inconsistent with, the MFR, AET submits that those should not be the standard against which AET is judged in this Proceeding. In this Reply Argument, AET will therefore limit its Reply to the MFR applicable to the Application.[591]

[586] Exhibit 20272-X1299, Calgary redacted argument, paragraphs 68-69, page 20.
[587] Exhibit 20272-X1299, Calgary redacted argument, paragraph 70, page 21.
[588] Exhibit 20272-X1309, ATCO Electric reply argument, paragraphs 195 and 197, pages 74-75.
[589] Bulletin 2006-25, Announcing the Approval in Principle of the Form an d Content of a Uniform System of Accounts and Minimum Filing Requirements for Alberta Electric Utilities.
[590] Decision 2007-017: EUB Proceeding, Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities, Application 1468565-1, March 6, 2007.
[591] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 198, page 75.

839. ATCO Electric submitted that its IT capital business cases were adequate, established the need for the projects, and established a reasonable forecast of the capital cost of these projects for the test period. It was the position of ATCO Electric that its IT capital business cases met all applicable MFR requirements. ATCO Electric submitted that the principal question for the Commission to address in this proceeding was whether the company had provided sufficient information to support the reasonableness of the proposed capital expenditures in the test period such that they could be assessed on their merits for inclusion in revenue requirements.[592]

840. ATCO Electric submitted that IT capital business cases for projects that exceed $500,000 over the test period are assessed against the following criteria to validate that the business outcomes provide benefits and customer value:

> a) Technical: supporting reliability of service; supporting asset management; providing required functionality to support business processes; reduce risk of prolonged IT outage by maintaining technology at vendor supported levels; providing capacity management; providing required performance improvements; required to support emergency service restoration.
> b) Opportunity: economic savings; productivity gains.
> c) Providing Health and Safety or Environment management support
> d) Required for regulatory compliance[593]

841. ATCO Electric provided a table[594] in which it summarized, for each software project over $500,000, the business justification, the alternatives considered and the benefits of the project. ATCO Electric provided cost information in its comparison of alternatives as well as examples of financial benefits of its forecast software projects as applicable.

842. However, ATCO Electric stated that calculating the incremental capital and operating costs, as well as annual costs for each alternative examined for a minimum 10-year period, and using a discount or investment rate to compare alternatives, were unnecessary in the context of the majority of the software business cases. ATCO Electric argued that projects for regulatory compliance, implementing automated systems to replace manual processes, improving utility and functionality, renewing software business licenses and undertaking upgrades to maintain vendor support, were all unsuitable for 10-year analysis.

843. ATCO Electric argued that Calgary had not disputed the business driver or benefits of any specific software business case and had provided only general comments regarding the sufficiency of ATCO Electric's business cases. ATCO Electric submitted that its forecast capital expenditures and additions for its software business cases were demonstrably justified and that Calgary's recommendation of a $15.7 million disallowance must be rejected.[595]

844. FTI reviewed ATCO Electric's response to Direction 92 from Decision 2013-358 and the sufficiency of information provided to support ATCO Electric's direct assigned capital projects. In Decision 2013-358, the Commission directed ATCO Electric to include certain information for any direct assigned capital project that has a forecast capital cost in excess of $5 million.[596] In

[592] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 203, pages 76-77.
[593] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 204, page 77.
[594] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 207, pages 77-86.
[595] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 208, pages 86-87.
[596] Decision 2013-358, paragraph 1096.

this application, ATCO Electric responded that it incorporated the additional information requested as part of each direct assigned business case in excess of $5 million.[597]

845. FTI reviewed compliance of selected projects[598] against a checklist of the documentation required to support those projects, per the Commission's direction. In response to a Commission IR, FTI clarified that the projects it selected for review were ones representing the majority of ATCO Electric's planned capital expenditures. FTI intentionally used the same projects that it used in assessing ATCO Electric's forecast PMCM costs. Completed projects, or projects that had been delayed or suspended by the AESO did not provide a valid basis for assessment and therefore were not included.[599]

846. FTI found deficiencies in the information ATCO Electric had been directed to file. Generally, it concluded that ATCO Electric's submissions "lack the detail and comprehensiveness required to allow a sufficient examination and testing of the reasonableness and accuracy of ATCO Electric's capital expenditures and additions forecasts." Specifically, FTI submitted that:

- The milestone schedules were inconsistent in the level of detail provided between projects. At a minimum, schedules should include start, finish and per cent completion for the following critical activities: clearing, foundations, tower assembly, tower erection, stringing and commissioning.
- There is a lack of detail at reporting stages aside from the PPS estimate in cost estimates. FTI recommended that ATCO Electric be directed to provide its monthly project status reports for all direct assigned system projects with forecast costs greater than $5 million.
- There is inconsistency in the level of detail in the cost reports included in the project descriptions of the business cases compared to that in the monthly reports.
- Project attributes should also include labour cost/km, materials/km, total line/km, labour cost/km/MVA, materials/km/MVA, and total line/km/MVA.[600]

847. In rebuttal, ATCO Electric addressed each of FTI's concerns as follows:

- Milestone schedules: because they are at an early stage, projects included in a GTA will not have a percentage other than zero per cent in clearing, foundations, tower assembly, tower erection, stringing and commissioning activities. For the remainder of projects, the completion per cent provided in the AESO monthly reports can be used to assess the reasonableness of forecast capital expenditures and capital additions in the GTA.
- Project status reports: these monthly reports are only prepared once a direction is received from the AESO. Furthermore, project status reports are not prepared in the pre-PPS planning stage per ISO rules. The "original budget" amount on the report would only reflect the amount of the direction until the PPS is approved and then that amount is used as the "original budget." For projects in the pre-PPS planning stage, ATCO Electric has provided high-level parametric estimates and the details of the historical projects which were the basis of those parametric estimates. ATCO Electric has provided sufficient

[597] Exhibit 20272-X0002, application, PDF page 279.
[598] The projects included in FTI's analysis were: 55125 – Birchwood 240-kV line and Substation, 55322 – Algar Area System Reinforcement, 57155 – Cold Lake Area Bourque-Bonnyville, and 57157 – St. Paul Substation and Line.
[599] Exhibit 20272-X0819, AET-CCA-2016FEB01-028, PDF page 27.
[600] Exhibit 20272-X0784, FTI evidence, PDF pages 41-42.

information to assess the reasonability of forecasts for projects in the pre-PPS planning stage.
- The breakdown of costs in the monthly AESO reports aligns with ISO Rule 9.1.3.1 and follows the AESO mandated template. The breakdown of the costs in the project descriptions follows Direction 92 from Decision 2013-358.
- The metrics provided in the project descriptions are sufficient to calculate the additional information and metrics recommended by FTI.

848. ATCO Electric submitted that it has fully complied with the MFR and Commission's directions[601] and that the additional information sought by FTI is at a level of detail not required by the Commission's direction. ATCO Electric requested that the Commission decline to direct ATCO Electric to implement the additional recommendations from FTI.[602]

Commission findings

849. The Commission has reviewed the various business cases identified by the interveners as being deficient, and finds that many of the cases related to IT and capital maintenance projects contain no substantive assessment of quantitative benefit. The Commission has previously emphasized the importance of thorough business case evidence incorporating complete analyses[603] and is concerned by ATCO Electric's failure to submit business cases that meet the Commission's requirements in this regard.

850. While the Commission is mindful of the interveners' proposals to augment or strengthen its previously issued guidelines, it does not believe this to be necessary. Previous decisions have clarified what is required in business cases and both the MFR and the enhanced description of business case criteria set out in Decision 3577-D01-2016 provide regulated utilities with more than sufficient guidance to prepare and present business cases that support their projects.

851. Commission Direction 92 from Decision 2013-358 required ATCO Electric to provide prescribed information in its next GTA and DACDA in respect of any individual direct assigned capital project having a forecast capital cost in excess of $5.0 million. The Commission finds that ATCO Electric has complied with this direction in its current GTA and is persuaded that the value of the information provided warrants including it in all of the utility's subsequent GTAs and DACDAs, until such time as the Commission may direct otherwise. The Commission is willing to accept the inclusion of some information in application updates (e.g., final cost reports) in circumstances where ATCO Electric indicates in the initial application that the information in question is not yet available. The Commission, however, is concerned that certain information is excluded[604] because a project's capital expenditures in the test period are less than $5.0 million. The Commission considers that the $5.0 million threshold should apply to the estimated total project cost, not the forecast costs in the test period, and that this guideline be strictly adhered to in all subsequent submissions.

[601] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 55-63.
[602] Exhibit 20272-X1298, ATCO Electric argument, PDF page 132.
[603] Decision 2013-358, paragraphs 415-416.
[604] For example, in Exhibit 20272-X1104 at PDF page 43, ATCO Electric indicated that attachments to the business case were removed in the updated business case because the capital expenditures for the New Little Smoky South 240-kV Substation project were less than $5 million in the test period.

852. With respect to FTI's evidence on the sufficiency of information provided by ATCO Electric in support of its direct assigned capital projects, the Commission will not direct ATCO Electric to implement FTI's recommendations.

853. Where inadequate business cases are identified or where no business case was provided for a project, the Commission may direct ATCO Electric to (1) remove the forecast project costs or some portion of the forecast costs, (2) use a placeholder for the forecast costs until adequate business cases are provided or (3) include the forecast costs, depending on the characteristics of the project and the deficiencies noted in the business case. Individual findings regarding the adequacy of specific business cases are addressed in the relevant capital sections below.

11.2 Capitalization policy

854. ATCO Electric provided its current asset capitalization policy (updated in December 2013) in Section 31 – Supplementary Information of its application. This policy describes the accounting treatment for capitalization of fixed assets. ATCO Electric defined fixed assets as "a unit of property which can be physically identified and has a useful life in excess of one year." The value of the asset can include costs which were related to its creation such as materials, direct and indirect labour, expenses, fringe benefits and administrative overhead.

855. ATCO Electric further delineated capital expenditures from O&M expenditures by defining capital expenditures as construction or purchase of a new asset, or upgrade, rehabilitation or replacement of an asset.[605]

856. The asset capitalization policy was not addressed in any party's arguments or reply arguments.

857. ATCO Electric's asset capitalization policy remains unchanged since the previous GTA.

11.3 2015 opening rate base

858. ATCO Electric has requested approval of a 2013 actual closing rate base of $3,963.8 million and a 2014 actual closing rate base of $5,095.6 million.[606]

859. Significant capital additions from 2012 to 2013 include: Substation Rebuilds Capital Maintenance ($14.8 million), Southeast Bulk System Reinforcement ($608.7 million), Arcenciel Synchronous Condenser ($35.8 million), Livock 240-kV Phase Shifting Transformer Addition ($38.4 million), Edith Lake to Sarah Lake 144-kV Line Upgrade ($20.1 million), North Fort McMurray Transmission Development ($124.5 million), and Cold Lake Development ($48.0 million).

860. Significant capital additions from 2013 to 2014 include: High Prairie to Triangle 144-kV Line Upgrade ($55.9 million), Kettle River Substation and 240-kV Line Tap ($49.4 million), Cold Lake Area Bourque-Bonnyville ($108.5 million), Kitscoty Area Development ($25.0 million), Southeast Bulk System Reinforcement ($25.5 million), Surmont II Stage 2 ($34.5 million), Hangingstone SAGD ($21.2 million), and Beartrap 144-kV Line and New Substation ($22.8 million).[607]

[605] Exhibit 20272-X0003, application, Section 31, PDF pages 3-6.
[606] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-1.
[607] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.

861. The actual capital additions to rate base for 2013 and 2014, along with the approved forecast amounts, are detailed in the following table:

Table 34. Comparison of 2012-2014 actual capital additions to forecast

	2012		2013		2014		
	Direct assigned	Non-direct assigned	Direct assigned	Non-direct assigned	Direct assigned	Non-direct assigned	Total
	($ million)						
Applied-for	1,257.0	124.6	1,361.9	139.3	2,028.1	139.5	5,050.4
Actual	571.8	108.3	1,033.4	96.9	417.3	67.8	2,295.5
$ over (under) applied-for to actual	685.2	16.3	328.5	42.4	1610.8	71.7	2,754.9
% over (under)	54.5%	13.1%	24.1%	30.4%	79.4%	51.4%	54.5%

Source: Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-5.

862. Other than the actual additions to rate base for 2013 and 2014 for the direct assigned capital projects, which are included in the direct assigned capital projects deferral account, ATCO Electric's request for approval of the remainder of the 2013 and 2014 actual additions has been addressed in this section of the decision.

863. ATCO Electric explained that the observed variance in non-direct assigned projects in 2013 was mainly attributable to the Transmission Rights-of-Way Widening and McNeill HVDC Control Replacement capital maintenance projects and the Nisku Panel Shop buildings capital project. The Transmission Right-of-Way capital additions were less than forecast due to delays caused by weather and related poor ground conditions. The McNeill HVDC Control Replacement capital additions were less than forecast due to project schedule adjustments required to resolve product quality issues that arose during the engineering and construction phase of the project. The Nisku Panel Shop costs were not included in the 2013 approved additions because this project was completed and capitalized in 2015[608] instead of 2013, as forecast. ATCO Electric stated that the costs were required to centralize multiple locations with a view to reducing future transportation and communication delays in panel manufacturing and delivery timelines.[609]

864. ATCO Electric explained that the observed variance in non-direct assigned projects in 2014 was mainly attributable to the Transmission Capital Maintenance – Lines, Substation Rebuilds (capital maintenance), Telecommunication Capital Maintenance and the CUL 43 Replacement (isolated generation) projects. Capital additions in 2014 also included costs for construction of a material storage building - the Nisku Panel Shop which were not included in the 2014 approved additions. The Transmission Capital Maintenance – Lines capital additions were less than forecast due to delays in line relocation projects to accommodate customer schedules. The delayed projects will be completed in future years.

865. Substation Rebuilds capital additions were less than forecast due to project scheduling. For example, the Steepbank substation rebuild was put on hold due to lack of customer commitment; the Vegreville substation rebuild was coordinated with direct assigned project work: and both the Keg River and Muskeg River substation rebuild schedules were adjusted to explore alternative solutions. These delays were partially offset by increased costs for the Swan

608 Exhibit 20272-X0281, AET-AUC-2015JUN08-0107, PDF page 232.
609 Exhibit 20272-X0003, application, Section 31, PDF pages 44-46.

River and Battle River substation rebuilds due to market escalation and outage coordination, respectively. The Telecommunications Capital Maintenance capital additions were greater than approved due to increased scope for a telecommunication tower corrosion management program. The CUL 43 replacement capital additions were less than forecast because the project is on hold to evaluate the transmission strategy for Jasper.[610]

866. The 2014 capital additions also included $4.0 million related to ATCO Electric's proposed asset management program.[611] Calgary requested that the Commission deny the $4.0 million capital amounts for 2014 related to the asset management program on the basis that ATCO Electric had not provided sufficient justification for pursuing it. According to Calgary, ATCO Electric's business case did not meet previous Commission directives in that it was missing a detailed cost/benefit analysis, a benefits realization plan and an ISO 55001 certification report.[612] ATCO Electric's asset management program is addressed in Section 11.4.3.

867. In argument, ATCO Electric stated that it provided business cases for capital maintenance, software and general plant and equipment projects that were completed in 2013 and 2014 but which were not forecast in the 2013-2014 GTA.[613]

868. In reply argument, the RPG stated that it had not reviewed ATCO Electric's opening rate base and therefore had no comments with respect to ATCO Electric's argument in support of opening rate base. The RPG clarified that this does not mean it agrees with ATCO Electric's positions or arguments on this matter.[614]

869. No other parties commented on ATCO Electric's applied-for opening rate base.

Commission findings

870. With the exception of certain capital additions addressed below, the Commission accepts the variance explanations provided by ATCO Electric, both in its AUC Rule 005[615] filings and in response to a Commission IR,[616] related to its 2013 and 2014 capital additions. The Commission approves the 2013 and 2014 rate base additions as filed, subject to any future adjustments that may arise as a result of the true-up of direct assigned capital additions which are being examined in Proceeding 21206 and subject to the disallowances to asset management capital additions in 2014 as directed by the Commission in Section 11.4.3, below.[617]

871. ATCO Electric stated that it provided variance explanations in the application and business cases for any projects which were completed in 2013-2014 but which were not contemplated in the 2013-2014 GTA. However, several projects identified in the application appear to have been filed without accompanying business cases. The following table shows approved capital additions compared to actual capital additions for projects which are not approved to be added to rate base at this time.

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610 AUC Rule 005 filing for 2014.
611 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4, under Direct General PP&E – Transmission Asset Mgmt Program.
612 Exhibit 20272-X1299, Calgary argument, PDF page 33.
613 Exhibit 20272-X1298, ATCO Electric argument, PDF page 125.
614 Exhibit 20272-X1307, RPG reply argument, PDF page 100.
615 AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.
616 Exhibit 20272-X0281, AET-AUC-2015JUN08-098 Attachment 1.
617 Proceeding 21206, ATCO Electric Transmission, Application for Disposal of 2013 and 2014 Transmission Deferral Accounts and Annual Filing for Adjustment Balances.

Table 35. 2013 and 2014 rate base additions over $500,000 with significant variance

	2013(2)		2014(2)		
	Approved additions	Actual additions	Approved additions	Actual additions	Reason for disallowance
	($ million)				
Telecommunication site power backup	-	-	5.0	5.9	No variance explanation was provided
SCADA/EMS: Operational information systems	-	-	0.9	0.1	No variance explanation was provided
Refurbish/replace engines and turbines	-	-	1.0	0.5	No variance explanation was provided
Transmission isolated operations capital maintenance	-	-	1.9	1.3	No variance explanation was provided
Tools, instruments and equipment	-	-	2.7	7.2(1)	Some costs associated with asset management
Software: Asset management	-	-	0.0	0.5(1)	Cost associated with asset management
Software: Technology enhancements	0.1	0.9	-	-	No variance explanation was provided
Software: Capital and O&M forecasting project	0.0	0.6	-	-	No business case was provided
Software: Intelex	0.0	0.7	-	-	No business case was provided
Software: Windows 7 upgrade	0.8	1.7	-	-	No variance explanation was provided
Software: Oracle R12 upgrade	-	-	0.0	1.8(1)	No business case was provided
General leasehold improvement capital division	0.0	3.9	-	-	No business case was provided
Stettler Service Building	0.1	0.8	-	-	No variance explanation was provided
Nisku panel shop	0.0	7.3	0.0	0.0	No business case was provided
Nisku fabrication building	-	-	0.0	1.8	No business case was provided
Total	**1.0**	**15.9**	**11.5**	**19.1**	

Notes:
(1) These amount are included in the asset management program opening rate base amounts which are denied.
(2) Values are included only if they meet the $500,000 variance threshold and no variance explanation or business case was provided.

Source: Exhibit 20272-X0003, application, Section 31, PDF pages 44-46 and AUC Rule 005 filing for 2014.

872. ATCO Electric bears the onus to demonstrate that its submitted capital addition amounts are reasonable. As stated in the MFR, providing variance explanations and business cases for any significant capital project is a minimum requirement for discharging this onus in any GTA.

> Applicants shall provide details in support of large volume capital additions (i.e. distribution extensions, services, meters, etc.), which may include number of units, unit costs and an explanation of changes in these items.
> Applicants shall explain the nature of, and reason for, all difference between property, plant, and equipment and capital additions included in the determination of revenue requirement and property, plant, and equipment and capital additions included in audited financial statements.

Business Cases

Applicants shall provide business cases for capital projects and programs in excess of $500,000 (Smaller applicants with revenues less than $100 million, excluding the cost of energy will be subject to a materiality limit of $100,000) 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; and
- The date of preparation and the date of approval.[618]

873. AUC Rule 005 also sets out requirements for variance explanations:

> 4.3 In the report, a utility must provide detailed explanations of the variances reported on its schedules, within the parameters outlined below.
>
> > 4.3.1 Variance explanations must be presented on a separate page of the report, referenced to the specific schedule and line item being explained and must be sufficiently detailed so as to provide an explanation of the nature and cause of the variance.
> >
> > 4.3.2 For years for which there is an approved forecast for the year, actual results must be compared with the approved forecast, with explanations provided for significant variances as described below.
> >
> > …
> >
> > 4.3.5 If there is not an approved forecast for the year, actual results must be compared with the actual results of the prior year.[619]

874. The Commission finds that there is insufficient information on the record of this proceeding to approve the requested rate base additions for 2013 and 2014 for the projects included in Table 35, above. Accordingly, ATCO Electric is directed to remove the capital additions from opening rate base in the compliance filing and to provide business cases for the work that was actually completed in 2013 and 2014 for those projects. The Commission will re-evaluate the requested capital additions for these projects upon review of the variance explanations and/or business cases provided in the compliance filing.

11.4 Overview of 2015-2017 forecast capital expenditures and additions

875. ATCO Electric has separated its capital projects into two categories: direct assigned and non-direct assigned. Direct assigned capital projects are those that are directly assigned to ATCO Electric by the AESO. ATCO Electric further subdivides its non-direct assigned capital projects into the following categories:

[618] Minimum Filing Requirements – Phase 1, PDF page 109.
[619] AUC Rule 005, Section 4.3.

- capital maintenance
  - general
  - telecommunication
  - Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS)
- isolated generation
- direct general property, plant and equipment (PP&E)
- software
- buildings

876. Capital expenditures are the amounts that are forecast to be spent in the year, while capital additions are the cumulative amounts spent on capital projects that are forecast to be completed during the year and added to rate base. With the exception of return on the direct assigned capital projects, for which ATCO Electric receives deferral account treatment, ATCO Electric bears the forecast risk for 2015, 2016 and 2017 associated with the return on all other capital additions that are forecast to take place in the test period.

877. The breakdown of the forecast amounts for 2015, 2016 and 2017 were included in the revenue requirement schedules[620] that were filed in conjunction with the revised application and are as follows:

Table 36. Forecast capital expenditures and additions for test period

	2015 forecast		2016 forecast		2017 forecast	
	Expenditures	**Additions**	**Expenditures**	**Additions**	**Expenditures**	**Additions**
	($ million)					
Direct assigned	246.1	1,999.4	200.4	182.9	272.8	204.1
Non-direct assigned						
Capital maintenance						
General	81.2	104.1	98.3	119.2	94.3	86.5
Telecommunication	17.0	18.2	25.0	21.6	17.6	24.7
SCADA/EMS	0.7	0.9	0.9	0.9	1.1	1.1
Total capital maintenance	99.0	123.2	124.2	141.7	113.0	112.3
Isolated generation(1)	2.8	4.5	4.1	4.2	3.8	3.9
Direct general PP&E	14.1	14.1	15.5	16.8	13.2	13.2
Buildings	0.9	3.8	9.7	9.7	5.8	5.8
Software	6.7	7.3	9.3	9.3	5.7	5.7
Total non-direct assigned	123.5	152.9	162.8	181.7	141.5	140.9
Net salvage		(14.0)		(13.2)		(2.8)
Total(2)	**369.6**	**2,138.3**	**362.9**	**351.4**	**413.6**	**342.2**

Note:
(1) Per Exhibit 20272-X0002, application, PDF page 526: the isolated generation portfolio is included in the capital maintenance program.
(2) Numbers may not add up due to rounding.

[620] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.

878. As noted earlier in this decision, interveners raised a number of issues that are not specific to any particular capital project but instead are common to the entire category of capital projects. These common issues were as follows:

- significant transmission cost increases
- uncertainty adjusted forecasts
- zero-based budgeting
- reasonableness of project management costs
- risk register
- decision matrix
- contingency estimates using the risk register approach
- adequacy of business cases

879. These issues were addressed in Section 11.1 above.

11.4.1 Direct assigned capital projects

880. Direct assigned capital projects, which are designed, built and operated by the TFO on the AESO's direction, are subjected to proceedings to assess the project need, with the AESO submitting a needs identification document (NID) to the Commission for approval. ATCO Electric stated that business cases were provided for direct assigned capital projects over $500,000 within the test period. These business cases provide information about the status of the project, including the AESO's NID submission to the Commission. ATCO Electric provided only project summaries for projects that would incur less than $5 million in the test period. The largest capital expenditures and additions in the test period are associated with major transmission system development identified by the AESO. The most significant of these projects, the EATL project, is designated critical transmission infrastructure by the government of Alberta, and therefore no NID application was required for this project.

881. Throughout the proceeding, ATCO Electric provided updates to the forecast project costs and removed cancelled projects from its capital forecasts. The latest forecast of direct assigned capital projects is as follows:

Table 37. Direct assigned projects summary

Project number	Project name	System or Customer	ISD[3]	2014 actual capex[1]	2015 capex	2015 cap adds[2]	2016 capex	2016 cap adds	2017 capex	2017 cap adds
				($ millions)						
51103	Arcenciel Synchronous Condenser	System	*2013-05-31	0.9	5.7	5.7	-	-	-	-
53320	High Prairie to Triangle 144-kV Line Upgrade	System	*2014-11-26	37.1	8.5	8.5	0.3	0.3	-	-
53600	New Little Smoky South 240-kV Substation	System	5/1/2022	-	-	-	-	-	0.7	-
53605	Wesley Creek to Little Smoky South 240-kV Line	System	5/1/2022	0.1	0.1	-	-	-	5.0	-
53750	Edith Lake to Sarah Lake 144-kV Line Upgrade	System	*2013-06-14	0.1	0.2	0.2	-	-	-	-
54904	Jasper Transmission Interconnection	System	5/1/2018	0.7	1.8	-	7.8	-	52.1	-
55001	Salt Creek - 240-144-kV Substation	System	*2012-09-13	0.0	0.1	0.0	-	-	-	-
55125	Ells-Birchwood 240-kV Line and Substation	System	*2015-04-01	20.8	0.1	29.1	-	-	-	-

Project number	Project name	System or Customer	ISD[3]	2014 actual capex[1]	2015 capex	2015 cap adds[2]	2016 capex	2016 cap adds	2017 capex	2017 cap adds
				($ millions)						
55126	Ells - 9L76/9L08 240-kV DC line	System	Unknown (project on hold)	3.6	0.2	-	-	-	0.8	-
55322	Algar Area System Reinforcement	System	*2015-07-24	20.6	20.1	45.9	-	-	-	-
55703	Heart Lake Station Expansion	System	*2015-08-21	10.9	8.6	20.3	0.4	0.4	-	-
55730	Livock 240 – 144-kV Substation	System	*2013-03-07	0.0	0.1	0.1	-	-	-	-
55732	Livock Interconnection	System	12/1/2018	-	0.2	-	0.8	-	1.0	-
55737	Thickwood Hills Development	System	9/30/2018	0.7	1.7	-	28.4	-	51.4	-
56539	Cold Lake Development	System	*2014-01-31	3.1	4.7	4.7	-	-	-	-
56767	Tinchebray 972S - Breakers and Bus Work	System	4/1/2019	-	-	-	0.3	-	2.0	-
56768	9LX02 (Boundary-Tinchebray)	System	4/1/2019	-	-	-	0.3	-	1.3	-
57120 and 57121	Central East Clearance Mitigation	System	Unknown (projects were cancelled then reactivated by the AESO)	0.6	-	-	-	-	-	-
57151	St. Paul Area – Watt Lake and Whitby Lake Substations	System	*2014-06-25	1.9	0.1	0.1	-	-	-	-
57155	Cold Lake Area - Bourque-Bonnyville	System	10/1/2016	65.9	(0.5)	(0.5)	2.5	19.1	-	-
57156	Kitscoty Area Development	System	*2014-11-30	13.3	0.3	0.3	-	-	-	-
57157	St. Paul Substation and Line	System	8/1/2016	26.6	3.4	(0.5)	19.2	65.7	-	-
58001	Edmonton–Calgary 500-kV East Route (EATL)	System	*2015-12-18	737.0	91.1	1,757.2	42.3	42.3	-	-
58005	Southeast Bulk System Reinforcement	System	*2015-04-01	23.1	9.0	31.6	-	-	-	-
5XXX1	Little Smoky South to Big Mountain 240-kV Line	System	12/1/2020	-	-	-	1.0	-	-	-
5XXX2	New Drury 2007S	System	4/1/2019	-	-	-	0.4	-	1.3	-
5XXX3	New 7L65 In-Out to Drury	System	4/1/2019	-	-	-	0.3	-	0.4	-
5XXX4	New 7L129 In-Out to Drury	System	4/1/2019	-	-	-	0.3	-	0.4	-
5XXX5	Thornton Add Voltage Support	System	12/1/2018	-	-	-	0.8	-	2.0	-
5XXX6	MRM 240-kV Line Relocate	System	12/1/2020	-	-	-	-	-	1.0	-
5XXX7	7L113 Rebuild	System	12/1/2020	-	-	-	0.5	-	4.0	-
51074	Fort Nelson Remedial Action Scheme	Customer	12/1/2016	0.0	0.0	-	0.2	0.4	-	-
51162	Blumenort - Windy Hills 144-kV Transmission Line	Customer	3/1/2017	0.1	0.0	-	3.1	-	13.6	18.1
51168	Norcen Substation Capacity	Customer	2/1/2016	0.6	3.1	-	2.0	5.9	-	-
51181	Carmon Creek Cogen	Customer	9/1/2017	8.6	5.7	-	6.7	-	24.8	46.2
51440	Whitetail Peaking Station	Customer	3/1/2017	0.5	0.3	-	3.4	-	1.6	6.0
51715	Brintnell Transformer Upgrade	Customer	7/1/2016	-	0.3	0.3	-	-	-	-
51745	Wabasca 25-kV Breaker Addition	Customer	7/1/2016	0.2	0.1	-	1.8	2.2	-	-
51750	Eureka River 861S Xmer addition	Customer	3/1/2017	-	0.2	-	0.5	-	6.1	6.8
53034	Ksituan River 754S Capacity Upgrade	Customer	5/1/2018	-	0.1	-	0.5	-	2.3	-
53440	Thornton New POD (Kakwa POD)	Customer	8/17/2016	0.1	3.4	-	14.4	17.9	-	-
53593	Grande Prairie POD	Customer	12/1/2018	0.1	0.4	-	6.8	-	8.3	-

Project number	Project name	System or Customer	ISD[3]	2014 actual capex[1]	2015 capex	2015 cap adds[2]	2016 capex	2016 cap adds	2017 capex	2017 cap adds
				($ millions)						
54001	Fox Creek DTS Increase (Fan Addition)	Customer	*2015-06-24	-	0.1	0.1	-	-	-	-
54002	Fox Creek Breaker Addition	Customer	9/1/2016	-	0.2	-	1.3	1.5	-	-
54020	Muir POD	Customer	3/1/2018	-	0.2	-	2.0	-	6.2	-
54156	Aspen 240-kV Line and Sub	Customer	12/1/2017	-	-	-	5.0	-	30.0	35.0
54381	Mercer Hill Breaker Addition	Customer	*2015-01-07	1.0	0.1	1.4	-	-	-	-
54501	Wapiti 823S Capacity Addition	Customer	12/1/2017	-	0.1	-	0.5	-	4.2	4.8
54954	Maxim Power Generator Increase	Customer	4/1/2017	-	-	-	0.5	-	3.5	4.0
55187	Service for MacKay SAGD	Customer	*2015-04-01	9.7	1.7	15.7	-	-	-	-
55325	Sweetheart Lake (Algar Expansion)	Customer	*2015-08-01	7.1	10.1	17.9	0.4	0.4	-	-
55579	Secord Substation	Customer	*2015-09-21	5.7	13.1	19.0	0.3	0.3	-	-
55622	Cheecham POD	Customer	*2015-05-01	8.0	5.5	14.5	-	-	-	-
55633	Surmount II Engstrom (Stage 3)	Customer	*2015-10-01	17.0	25.5	43.3	0.5	0.5	-	-
55655	Bohn POD	Customer	*2014-05-01	5.2	0.5	0.5	0.4	0.4	-	-
55680	Hangingstone SAGD	Customer	*2014-10-16	15.7	0.2	0.2	-	-	-	-
55706	Edwards Lake Substation Connection	Customer	3/1/2017	0.1	-	-	0.5	-	1.4	2.2
55750	Dover West Leduc	Customer	7/1/2019	(0.1)	-	-	-	-	0.3	-
55797	MacKay POD	Customer	7/1/2016	1.9	14.6	-	2.2	18.7	-	-
56101	Vilna 777S Substation Contract Capacity Increase	Customer	*2015-06-03	0.0	0.1	0.1	-	-	-	-
56352	Mahihkan 837S Substation 25-kV Breaker Addition	Customer	1/1/2017	-	0.4	-	1.4	-	0.1	1.9
56642	La Corey Capacity Upgrade	Customer	*2014-12-10	7.3	0.4	0.4	-	-	-	-
56655	Kent Generator - Central East	Customer	6/1/2017	0.0	0.6	-	1.7	-	11.5	13.7
56660	Beartrap 144-kV Line and New Substation	Customer	*2014-04-01	8.9	0.1	0.1	-	-	-	-
56810	Grizzly Bear Wind Facility Connection	Customer	12/1/2017	0.7	0.3	-	5.0	-	15.0	21.2
56865	Mainstream Wainwright	Customer	3/1/2017	-	-	-	-	-	0.3	0.3
58180	Spirit River POD Substation	Customer	1/1/2017	0.0	0.8	-	14.2	-	0.5	15.5
58181	Simonette 733S Substation Capacity Upgrade	Customer	9/9/2016	0.1	1.1	-	5.3	6.5	-	-
58215	Sharp Hills Wind Farm	Customer	4/1/2018	-	-	-	-	-	1.0	-
58562	Hand Hills Wind Project	Customer	12/31/2018	(0.0)	-	-	-	-	8.4	-
58569	Hand Hills Wind Power Facility	Customer	12/31/2018	0.0	0.0	-	-	-	6.0	-
58902	Monitor Substation Capacity Upgrade	Customer	*2015-01-22	2.1	1.0	3.7	-	-	-	-
58923	Currant Lake Substation	Customer	10/1/2019	0.2	-	-	0.2	-	0.2	-
58924	Armitage Substation	Customer	10/1/2019	0.2	-	-	0.2	-	0.3	-
58925	Cavendish Substation	Customer	10/1/2019	0.1	-	-	0.3	-	0.3	-
58965	Heartland Pump Station	Customer	11/1/2017	0.5	0.2	-	6.8	-	8.4	16.0
58970	Bohn 913S Substation Transformer Addition	Customer	2/1/2017	0.0	0.6	-	5.1	-	0.8	6.5
58971	Bauer 918S Substation Transformer Addition	Customer	2/1/2017	0.1	0.5	-	3.7	-	1.6	5.9

(1) Capex: capital expenditures.
(2) Cap adds: capital additions.

(3) *Actual ISD.
(4) Source: Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4; Exhibit 20272-X1105, revised business cases – clean; and, Exhibit 20272-X0738, AET-AUC-2015DEC30-002(a) Attachment 1.

882. ATCO Electric stated that forecast capital expenditures and additions will increase by $41.9 million in the test period due to an increase in the forecast for EATL, based on the December 31, 2014 monthly AESO progress report. This progress report explained that the additional costs are due mainly to an increase in the estimate of construction contract closeout costs for vendor change proposals for both line and converter stations.[621] ATCO Electric proposed to reflect this change in the compliance filing.[622]

Commission findings

883. The Commission finds that for direct assigned projects which are 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. These forecasts are approved, subject to adjustments related to directions elsewhere in this decision (such as the inflation factors addressed in sections 5.2.1 and 5.3) and the directions below.

884. Consistent with the Commission's findings in Section 11.4.1 above, there is a preference for the best available information when evaluating requested revenue requirement cost components. Accordingly, ATCO Electric is directed to update the direct assigned capital forecasts as proposed for the increase in the EATL forecast capital expenditures and additions, in the compliance filing.

885. The Commission reminds ATCO Electric that it bears the onus of demonstrating that the costs of its projects are reasonable, and a thorough investigation of direct assigned project costs will be conducted when the prudence of the final project costs are examined by the Commission during subsequent DACDA proceedings.

886. The Commission discusses certain direct assigned projects in the subsections below.

11.4.1.1 System projects

11.4.1.1.1 51103 – Arcenciel Synchronous Condenser

887. The only information provided on the record of this proceeding relating to estimated costs for this project is a letter from the AESO to ATCO Electric that was submitted as an attachment to the revised application. The letter contains a schedule of transmission capital expenditures for the 2015-2017 period and states that the Arcenciel Synchronous Condenser project is closed and that trailing costs are "reasonable as per ATCO comments." The "ATCO comments" referenced in the schedule were not provided.[623]

[621] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 17.
[622] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 161.
[623] Exhibit 20272-X1100, revised application – clean, Attachment 10.3, PDF page 205.

11.4.1.1.2 53750 – Edith Lake to Sarah Lake 144-kV Line Upgrade and 55001 – Salt Creek – 240-144-kV Substation

888. The Edith Lake to Sarah Lake 144-kV Line Upgrade project is part of the North Central Transmission Development.[624] The capital additions for this project are subject to true-up in ATCO Electric's current 2013-2014 DACDA proceeding.[625]

889. The Salt Creek 240-144-kV Substation project is part of the North Fort McMurray Transmission Development.[626] Its trailing costs for 2013-2014 are also included in ATCO Electric's current 2013-2014 DACDA proceeding.[627]

890. Apart from references to these projects in the GTA schedules, there is no information on the record which describes these projects or the work which was to be completed in the test period.

11.4.1.1.3 55730 – Livock 240 – 144-kV Substation

891. The Livock 240-144-kV Substation project is part of the North Fort McMurray Transmission Development.[628] Trailing costs of negative $0.6 million for 2013-2014 are included in the utility's current 2013-2014 DACDA proceeding.[629]

892. Apart from references to these projects in the GTA schedules, the only information provided on the record of this proceeding regarding this project was the AESO report on project procurement in compliance with ISO Rule 9.1.5.[630]

11.4.1.1.4 56539 – Cold Lake Development, 57151 – St. Paul Area – Watt Lake and Whitby Lake Substations and 57156 – Kitscoty Area Development

893. The Cold Lake Development, St. Paul Area – Watt Lake and Whitby Lake and Kitscoty Area Development projects are part of the Central East Transmission Development.[631] The capital additions for these projects are subject to true-up in ATCO Electric's current 2013-2014 DACDA proceeding.[632]

894. The variance explanations for the 2014 capital expenditures provided in the AUC Rule 005 filings, which were provided in response to an IR in this proceeding, note that the expenditures for all three projects were higher than forecast due to construction work which was deferred from 2013 into 2014.[633]

895. Apart from references to these projects in the GTA schedules and the above mentioned IR response, the only other information provided on the record of this proceeding was the project management plan for the Cold Lake Development project.[634]

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624 Exhibit 20272-X0002, application, PDF page 522.
625 Proceeding 21206, Exhibit 21206-X0009, Attachment 1 – summary.
626 Exhibit 20272-X0002, application, PDF page 522.
627 Proceeding 21206, Exhibit 21206-X0001, Attachment 5, trailing cost summary.
628 Exhibit 20272-X0002, application, PDF page 522.
629 Proceeding 21206, Exhibit 21206-X0001, Attachment 5, trailing cost summary.
630 Exhibit 20272-X0368, AET-CCA-2015JUN08-007(c) revised, PDF pages 30-38.
631 Exhibit 20272-X0002, application, PDF page 522.
632 Proceeding 21206, Exhibit 21206-X0009, Attachment 1 – summary.
633 Exhibit 20272-X0284, AET-AUC-2015JUN08-003 Attachment 3, PDF page 167.
634 Exhibit 20272-X0345, AET-CCA-2015JUN08-090 Attachment 2, PDF pages 607-634.

Commission findings

896. With respect to projects 51103 – Arcenciel Synchronous Condenser, 53750 – Edith Lake to Sarah Lake 144-kV Line Upgrade, 55001 – Salt Creek 144-240-kV Substation, 55730 – Livock 240-144-kV Substation, 56539 – Cold Lake Development, 57151 – St. Paul Area – Watt Lake and Whitby Lake Substations and 57156 – Kitscoty Area Development, there is no information on the record of this proceeding that would enable the Commission to evaluate the reasonableness of the forecast costs in the test period. These projects were energized prior to the test period and while some trailing costs are expected, it is not clear what work will be completed in the test period. While certain of these projects[635] do not meet the minimum $500,000 threshold to provide business cases per the MFR, the concern remains that these projects were energized sufficiently long ago that trailing costs would be expected to be negligible by this point in time. Certain projects were also delayed without an explanation being provided.[636] The Commission cannot find the associated forecast costs to be reasonable in the absence of information regarding the source(s) of the associated delays and justification for the fact that the associated work was not completed earlier. The trailing costs for these projects will be included in a future DACDA application where the prudence of those costs will be evaluated. The Commission expects that ATCO Electric will provide sufficient documentation in a DACDA to justify the requested additions.

897. The Commission finds that ATCO Electric has provided insufficient information on the record of this proceeding for the Commission to determine the reasonableness of the forecast costs for these projects. Accordingly, the Commission directs ATCO Electric to remove all forecast capital expenditures and additions, and related costs with respect to the Arcenciel Synchronous Condenser, Edith Lake to Sarah Lake 144-kV Line Upgrade, Salt Creek 144-240-kV Substation, Livock 144-240-kV Substation, Cold Lake Development, St. Paul Area – Watt Lake and Whitby Lake Substations and Kitscoty Area Development projects from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision.

11.4.1.1.5 53600 – New Little Smoky South 240-kV Substation

898. The New Little Smoky South 240-kV Substation project is part of the Peace River-Valleyview-Grande Prairie Area Transmission Development (PVGATD).[637] The project proposed to address the need for an additional switching station in the Valleyview area and is forecast to cost $24.7 million at completion.[638]

899. In the initial application, the New Little Smoky South Substation project had capital expenditures of $0.8 million forecast in 2016 and $9.8 million in 2017 with no capital additions forecast in the test period.[639] The forecast ISD was May 1, 2019.[640]

900. The ISD for this project was not updated in the utility's O&U filing, but its forecast capital expenditures were revised. In the final application update on February 23, 2016, the

[635] Namely, Edith Lake to Sarah Lake 144-kV Line Upgrade, Salt Creek 144-240-kV Substation and Livock 240-144-kV Substation projects.
[636] Namely, Cold Lake Development, St. Paul Area – Watt Lake and Whitby Lake Substations and Kitscoty Area Development projects.
[637] Exhibit 20272-X0002, application, PDF page 523.
[638] Exhibit 20272-X1104, PDF pages 40-41.
[639] Exhibit 20272-X0004, Schedule 10-4.
[640] Exhibit 20272-X0155, PDF page 2.

project ISD was revised to May 1, 2022 and the capital expenditures were lowered to $0.7 million in 2017.[641] The ISD was updated in response to the AESO's Long-Term Transmission Plan issued in November 2015[642] pursuant to which the PVGATD program was put on hold under the low growth scenario.[643]

901. The revised forecast costs in the test period were based on the estimated effort required to complete planning activities, some siting and routing and anticipated work with the AESO on studies, based on historical experience with similar projects.[644]

11.4.1.1.6 53605 – Wesley Creek to Little Smoky South 240-kV Line

902. The Wesley Creek to Little Smoky South 240-kV Line (Wesley Creek) project is part of the PVGATD.[645] The project proposed to construct approximately 180 km of double circuit 240-kV line between Wesley Creek 834S substation and the proposed New Little Smoky South substation and is forecast to cost $355.6 million at completion.[646]

903. In the initial application, the Wesley Creek project had capital expenditures of $0.1 million forecast in 2015, $0.4 million forecast in 2016 and $51.1 million in 2017 with no capital additions forecast in the test period.[647] The forecast ISD was May 1, 2019.[648]

904. In the O&U filing, this project's ISD was not updated but the capital expenditures were revised. In the final application update on February 23, 2016, the project ISD was pushed back to May 1, 2022 and the capital expenditures were downwardly revised to $5.0 million in 2017.[649] 2015 actual capital expenditures for this project were $0.1 million and consisted of an assessment cost for the overall PVGATD program that was allocated to the Wesley Creek project. The assessment included a review of (1) the existing assets in the area, (2) possible expansions of existing substations, and (3) different constraints and opportunities to meet the need in the area.[650]

905. The ISD was updated in response to the AESO's long-term plan issued in November 2015[651] pursuant to which the PVGATD program was put on hold under the low growth scenario.[652] The ISDs for the Wesley Creek and the New Little Smoky South 240-kV substations are the same because the two projects depend on one another for completion.[653]

906. The revised forecast costs in the test period were based on the estimated effort required to complete planning activities.[654]

641 Exhibit 20272-X1104, PDF page 40.
642 Exhibit 20272-X1106, AE-AUC-2015DEC30-002(b) revised, PDF page 140.
643 Transcript, Volume 9, pages 1581-1582.
644 Transcript, Volume 9, page 1584.
645 Exhibit 20272-X0002, application, PDF page 523.
646 Exhibit 20272-X1104, PDF pages 45.
647 Exhibit 20272-X0004, Schedule 10-4.
648 Exhibit 20272-X0160, PDF page 2.
649 Exhibit 20272-X1104, PDF page 45.
650 Transcript, Volume 9, page 1585.
651 Exhibit 20272-X1106, AE-AUC-2015DEC30-002(b) revised, PDF page 140.
652 Transcript, Volume 9, pages 1581-1582.
653 Transcript, Volume 9, page 1585.
654 Exhibit 20272-X1104, PDF page 46.

11.4.1.1.7 5XXX1 – Little Smoky South to Big Mountain 240-kV Line

907. The Little Smoky South to Big Mountain 240-kV Line project was added to ATCO Electric's forecast capital costs for the test period in its final application update filed on February 23, 2016. The project is part of the PVGATD.[655] In the revised application, ATCO Electric stated that significant portions of the PVGATD program have been deferred.[656]

908. The project proposed to construct 106 km of 240-kV line between the proposed Little Smoky and Big Mountain substations and is forecast to cost $92.0 million at completion. The forecast ISD was December 1, 2020.[657]

909. The forecast capital expenditures are $1.0 million in 2016 with no capital additions forecast in the test period. The forecast capital expenditures in the test period are required for planning activities.

910. This project was listed in a letter from the AESO to ATCO Electric. The letter, in turn, was submitted as an attachment to the revised application. It contains a schedule of transmission capital expenditures for the 2015-2017 period and states that the project is "reasonable as per ATCO's [comments] and business case."[658]

911. Neither this project, nor its late inclusion in ATCO Electric's application, was addressed in any party's argument or reply argument.

Commission findings

912. The findings below are applicable to projects 53600 – New Little Smoky South 240-kV Substation, 53605 – Wesley Creek to Little Smoky South 240-kV Line and 5XXX1 – Little Smoky South to Big Mountain 240-kV Line. These projects are large and complex, and are proposed to be completed after the test period. The projects are currently at the pre-PPS planning stage.

913. The Commission has reviewed the proposed schedule for these projects. The ISDs for these projects are determined by the AESO but the project schedules and/or ISDs have changed in application updates throughout this proceeding due to changes in system requirements. In testimony, the ATCO Electric witness confirmed that delays to projects are typically experienced in the early stages of a project.[659]

914. The Commission considers that the schedule changes that have occurred to date and the fact that several projects are currently on hold and still under review by the AESO,[660] suggest that it is very unlikely that any of the identified capital projects will actually be initiated during the test period. Accordingly, the Commission denies the forecast capital expenditures for these projects for the purposes of determining ATCO Electric's revenue requirement in 2016 and 2017. The Commission directs ATCO Electric to remove the forecast capital expenditures and related project costs from its forecast 2016 and 2017 revenue requirement, in the compliance filing to this decision.

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655 Exhibit 20272-X1100, revised application – clean, PDF page 140.
656 Exhibit 20272-X1100, revised application – clean, PDF page 139.
657 Exhibit 20272-X1105, PDF pages 316-318.
658 Exhibit 20272-X1100, revised application - clean, Attachment 10.3, PDF page 205.
659 Transcript, Volume 3, page 403, lines 22-25.
660 Transcript, Volume 9, page 1582.

915. Given that 2015 capital expenditures represent actual amounts, 2015 capital expenditures for these projects are approved as filed for the purposes of determining the 2015 revenue requirement.

11.4.1.1.8 54904 – Jasper Transmission Interconnection

916. The Jasper Transmission Interconnection project proposed to construct approximately 57 km of single circuit 69-kV line between AltaLink's Watson Creek 104S substation and the proposed Sheridan 2085S substation. The scope of the project includes the transmission line (12 km of which is in AltaLink territory and will be completed by AltaLink), salvage of distribution lines, and construction of a substation. This project was proposed as a solution to serve Jasper National Park as two of ATCO Electric's isolated generation plants reach end-of-life condition.[661]

917. The project is currently in the pre-PPS planning stage. The functional specification was issued on November 17, 2015 and was provided with the project business case.[662] The current project schedule proposed that the NID application be filed in July 2016 and the facility application be filed in August 2016.[663] Costs forecast to be incurred during the test period include those required to complete the facility application, engineering, and procurement and to commence construction. The forecast ISD for the project is May 1, 2018.

918. The project is forecast to cost $79.0 million at completion, and will consist entirely of systems costs.[664] $1.8 million, $7.8 million and $52.1 million are forecast to be expended in 2015, 2016 and 2017, respectively.[665] This forecast includes a contingency amount of $12.9 million which is based on a risk analysis using the latest available information.[666] The forecast amounts were revised from the initial application which forecast $1.6 million, $26.2 million and $50.3 million in 2015, 2016 and 2017, respectively.[667]

919. The 2014 and 2015 expenditures related to preparation of a business case to determine which solution was superior: building a new transmission line or refurbishing or fixing the Palisades generation facility. This assessment included identifying the current condition of the assets, the project's costs and risks, and conducting consultations with Parks Canada to identify possible routing. The remaining work activities outside the test period would include completion of construction, testing and commissioning, salvage, and project closeout.[668]

920. ATCO Electric stated that, in the event the project is energized during the test period, fuel costs would be reduced accordingly. ATCO Electric noted that it has requested that fuel costs be subject to deferral account treatment in this application.[669]

921. ATCO Electric identified several project risks related to external stakeholders, including:

- A NID or facility hearing is required due to stakeholder objections.

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661 Exhibit 20272-X1104, PDF pages 65-66.
662 Exhibit 20272-X1009, PDF pages 4-34.
663 Exhibit 20272-X1009, PDF page 2.
664 Exhibit 20272-X1009, PDF pages 38-45.
665 Per Mr. Vachon's testimony at page 1586 in Transcript, Volume 9, the 2015 amount is the actual cost for 2015.
666 Transcript, Volume 9, page 1589.
667 Exhibit 20272-X1104, PDF page 61-62.
668 Transcript, Volume 9, pages 1586-1587.
669 Exhibit 20272-X1106, AET-AUC-2015JUN08-092(c) revised, PDF page 115.

- Larger amount of stakeholders could influence the project.
- Aboriginal stakeholders.
- Restriction on line route within the national park (Parks Canada has placed limits on new rights-of-way within the national parks).
- Multi-TFO involvement.
- Federal and provincial regulatory approvals and permitting required.
- Consultations with stakeholders may produce changes or restrictions around construction timing.
- Parks Canada limited the right-of-way width which requires the use of non-standard conductors (Hendrix).[670]

922. In response to an IR, ATCO Electric indicated that it is mitigating the risks associated with receiving late Parks Canada approval or not receiving Parks Canada approval by involving Parks Canada in the project early on. For example, ATCO Electric started talks with Parks Canada while preparing the business case. To date, Parks Canada has informally indicated support for the project. ATCO Electric confirmed that it would wait for Parks Canada approval prior to applying for P&L.[671]

923. Mr. Vachon provided an update on the status of stakeholder consultations for this project at the oral hearing. He explained that 25 First Nations had initially been identified for consultation and that eight of these stakeholder groups had already confirmed that they harboured no concerns and, consequently, would not be involved in the consultation process going forward. None of the remaining 17 First Nations have yet indicated whether they have concerns or will be involved in future consultations.[672]

924. The project originally proposed to use a Hendrix conductor system due to Parks Canada restrictions on right-of-way. The ATCO Electric witness clarified that Hendrix is a reference to the conductor configuration to be used, not necessarily the supplier. In response to an IR, ATCO Electric confirmed that the cost of the Hendrix cable system is approximately four times that of standard aluminum clad steel reinforced (ACSR) conductor.[673] The currently proposed configuration uses an insulated conductor that allows for narrower rights-of-way in forested areas. The Hendrix cable design or insulated conductors will also tolerate trees leaning against a line without causing an outage. The insulated conductor that is currently proposed allows more typical structures to be used by ATCO Electric. The additional cost associated with the insulated conductor (an increase in the range of $5 million to$9 million) is expected to be included in the PPS estimate.[674]

925. FTI provided evidence on the feasibility of the proposed work schedule and the capital forecast. Given the update to forecasts in the February 23, 2016 filing by ATCO Electric, the RPG did not recommend that the Commission disallow capital expenditures as recommended by FTI but requested that the Commission direct ATCO Electric to refile an updated direct assigned capital forecast.[675] This request is addressed in Section 11.1.2. With regard to the proposed project schedule, FTI noted that ATCO Electric has revised the projected ISD for this project

[670] Exhibit 20272-X0282, AET-AUC-2015JUN08-058 Attachment 1, PDF pages 115-117.
[671] Exhibit 20272-X0282, AET-AUC-2015JUN08-057(a) and (b), PDF pages 100-101.
[672] Transcript, Volume 9, pages 1590-1591.
[673] Exhibit 20272-X0282, AET-AUC-2015JUN08-059(c), PDF page 120.
[674] Transcript, Volume 9, pages 1595-1596.
[675] Exhibit 20272-X1297, RPG argument, PDF page 160.

four times since the initial application. Schedule milestones have also been revised. In FTI's view, this "puts the degree of certainty in the forecast project schedule into question" and suggests that the forecast expenditures for the test period 'no longer appears appropriate" given the schedule uncertainty. FTI opined on the work that could reasonably be completed in the test period and, using benchmarking data, determined that the forecast for 2016 should be adjusted to $2.34 million and the forecast for 2017 should be adjusted to $23.49 million.[676]

926. In rebuttal, ATCO Electric stated that the PPS for this project was being finalized and that it anticipated its release by the scheduled date. It added that consultation with affected parties has commenced and the functional specification has been issued. ATCO Electric also took issue with the benchmarking data used by FTI, arguing that the PPS estimates used by FTI lack the accuracy of historical actual costs and include escalation and contingency values. ATCO Electric stated that the current status of the project is on track and therefore the current forecast is fully supported.[677]

Commission findings

927. NID and facility applications are the forums in which the Commission will consider the need, the proposed route, stakeholder consultation program, project design and environmental and other impacts associated with a transmission development project. For the purposes of this application, which assesses the reasonableness of costs forecast to be incurred over the test period, the Commission has restricted its review to consideration of the forecast costs.

928. The Commission has reviewed the proposed schedule for this project. The project schedule and ISD are determined by the AESO in consultation with the TFO and both are adjusted periodically to reflect current information. In the instant case, the project schedule and ISD were changed in application updates throughout this proceeding. As noted earlier, ATCO Electric has acknowledged that delays to projects are typically experienced in the early stages of a project.[678]

929. Given (1) the number of risks identified by ATCO Electric related to external stakeholders, any one of which could delay the project schedule, especially in its early stages; (2) the number of updates to the project schedule throughout this proceeding; and (3) the reality that the majority of large projects experience delays, the Commission considers there to be insufficient evidence on the record to support a finding that the project is more likely than not to proceed as currently scheduled.

930. The schedule provided by ATCO Electric in its rebuttal evidence[679] suggests that any delay experienced will push the construction of this project into 2018. This schedule also shows certain periods during which no work is allowed in the national park. Construction for the substation is scheduled to begin in August 2017 and line construction is planned for winter 2017/2018.[680] Given the uncertainty in the schedule, the potential for early delays to affect the timing of construction and the construction schedule constraints imposed by Parks Canada, the Commission is not persuaded as to the reasonableness of ATCO Electric's scheduled forecast for this project. The Commission considers that, based on current information, it is more likely that

[676] Exhibit 20272-X0784, FTI evidence, PDF pages 76-82.
[677] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 30-35.
[678] Transcript, Volume 3, page 403, lines 22-25.
[679] Exhibit 20272-X1120, ATCO Electric rebuttal – FTI evidence Attachment 5, PDF page 236.
[680] Transcript, Volume 9, page 1588.

substation construction will not be completed in 2017 and that line construction may not begin until early 2018.

931. Accordingly, the Commission directs ATCO Electric to reduce its forecast capital expenditures in 2017 by $9.5 million[681] for the purpose of determining ATCO Electric's revenue requirement in the compliance filing to this decision.

11.4.1.1.9 55126 – Ells – 9L76/9L08 240-kV DC Line

932. The Ells – 9L76/9L08 240-kV DC Line (Ells DC) project is part of the North West Fort McMurray Transmission Development program. The scope of this project includes construction of a new 240-kV switching station Ells River 2079S and 60 km of two single circuit side-by-side 240-kV lines. The project is forecast to cost $199.5 million at completion.[682]

933. The facility application and amended NID for the entire North West Fort McMurray Transmission Development program[683] were submitted to the Commission in June 2013, however, the proceeding was closed on September 19, 2013 at the request of the AESO.[684]

934. In the initial application, the Ells DC project had forecast capital expenditures of $2.0 million in 2015, $55.6 million in 2016 and $131.1 million in 2017, with capital additions of $199.5 million forecast in 2017.[685] The forecast ISD was March 31, 2017.[686]

935. In the O&U filing, the ISD was updated to March 2019 and the forecast capital expenditures in the test period were revised. In response to an IR subsequent to the O&U filing, ATCO Electric provided a letter from the AESO which suspended the project in order to review the need and timing for the project.[687] Thus, in the final application update on February 23, 2016, the project has no ISD and remains suspended. Capital expenditures were revised to $0.2 million in 2015 and $0.8 million in 2017.[688] As stated in the latter, the AESO expected to complete its review in the second half of 2016 and, in the hearing, ATCO Electric confirmed that no further updates with respect to the status of the Ells DC project had been provided to it by the AESO.[689]

936. The forecast capital expenditures in the test period and actual capital expenditures prior to the test period were required to complete planning, engineering and material procurement.[690] In the hearing, ATCO Electric's witness confirmed that some long lead items, such as

[681] The $9.5 million equals $7.0 million which approximately equals the forecast amount for line construction to be completed in 2017 plus $2.0 million which is approximately half of the forecast amount for substation construction to be completed in 2017 and plus $0.5 million in E&S.
[682] Exhibit 20272-X1104, PDF pages 84-86.
[683] Per the application in Exhibit 20272-X0002, the North West Fort McMurray Transmission Development program included the following projects: 55125 - Birchwood 240-kV Line and Substation, 55126 - Ells – 9L76/9L08 240kV D/C Line, 55127 - 9L95 Development, 55187 - Service for MacKay SAGD, 55750 - Dover West Leduc, 55751 - Dover North and 55797 - MacKay POD.
[684] Proceeding 2636, Exhibit 0111.01.AUC-2636.
[685] Exhibit 20272-X0004, Schedule 10-4.
[686] Exhibit 20272-X0155, PDF page 2.
[687] Exhibit 20272-X0758, AET-CCA-2015DEC30-015(b), PDF pages 183-184.
[688] Exhibit 20272-X1104, PDF page 84.
[689] Transcript, Volume 9, page s 1564-1565.
[690] Exhibit 20272-X1104, PDF page 85.

transmission poles, had been procured for this project and have not be re-purposed for any other projects.[691]

Commission findings

937. The most up-to-date evidence on the record for this project is that it is on hold until the AESO completes a review of the need for, and timing of, the project. After the review is complete, it is possible that the project could be cancelled. ATCO Electric has nonetheless forecast $0.8 million in capital expenditures in 2017. The Commission finds there is insufficient information on the record of this proceeding to determine the reasonableness of the forecast expenditures. The Commission approves the forecast capital expenditures as a placeholder and directs ATCO Electric, in the compliance filing, to provide an update on the project's status and on the forecast capital expenditures, as required and to provide details regarding the work which is forecast to be completed in the test period. Depending on the information provided in the compliance filing, the Commission may adjust the approved project capital expenditures.

11.4.1.1.10 55737 – Thickwood Hills Transmission Development

938. The Thickwood Hills Transmission Development (Thickwood) project proposed to construct a new 240-kV substation (Thickwood Hills 951S substation), 20 km of two new 240-kV single circuit transmission lines and two 240-kV single circuit transmission lines approximately two and 3.2 km each in an in-out configuration to the new Thickwood Hills substation. The project is required to support the Fort McMurray West 500-kV Transmission project and to meet current and forecast load growth near Fort McMurray.[692]

939. The project is currently in the facility application stage. The PPS was submitted to the AESO on November 18, 2015[693] and the facility application was submitted to the Commission on December 11, 2015.[694]

940. The project was forecast to cost $156.8 million at completion.[695] The capital expenditures were forecast to be $1.7 million in 2015, $28.4 million in 2016 and $51.4 million in 2017.[696] Costs to be incurred during the test period are required to complete the facility application, engineering, procurement and commence construction. The forecast ISD for the project is September 30, 2018.[697] The timeline for completion of this project depends on schedules of other projects. As ATCO Electric stated "… approval of the Permit and Licence is tied to the approval of P1655 Livock Interconnection and the West Fort McMurray 500-kV Transmission related projects."[698]

941. In the application update filed on February 23, 2016, ATCO Electric proposed to reflect the updated total project cost of $133.2 million for the Thickwood project in the compliance filing. The revised capital expenditures would be $1.7 million in 2015, $30.1 million in 2016 and $51.4 million in 2017.[699] The proposed revisions to the Thickwood Hills project are to align with

691 Transcript, Volume 9, pages 1566-1567.
692 Exhibit 20272-X1104, PDF page 134.
693 Exhibit 20272-X0974, PDF pages 19-61.
694 Proceeding 210303, Exhibit 21030-X0196.
695 Exhibit 20272-X0067, PDF page 2.
696 Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
697 Exhibit 20272-X1104, PDF page 1347-135.
698 Exhibit 20272-X0974, PDF page 120.
699 Exhibit 20272-X1104, PDF page 134.

the PPS estimate, cost and schedule information in the facility application, as well as to account for the earlier than expected hearing (which was scheduled to occur in June 2016 at the time of hearing for this proceeding).[700]

942. The PPS estimate included a change in conductor and tower type and associated foundations compared to those provided in the NID estimate. A bulk transmission line optimization study was completed prior to the PPS estimate which showed that ACSR 2x 477 Hawk conductor is the preferred conductor selection and single circuit wood H-frames are preferred over double circuit steel H-frame structures.[701] The line optimization is typically performed in parallel with the PPS preparation so that the information from a line optimization study is available for the PPS estimate.[702] In testimony, the ATCO Electric witness confirmed that the current cost estimates in the PPS assume single circuit wood H-frames.[703]

943. FTI provided evidence on the feasibility of the proposed work schedule and the capital forecast. Given the update to forecasts in the February 23, 2016 filing by ATCO Electric, the RPG did not recommend that the Commission disallow capital expenditures as recommended by FTI but requested that the Commission direct ATCO Electric to refile an updated direct assigned capital forecast.[704]

944. With regard to the proposed project schedule, FTI noted that ATCO Electric has revised the scheduled milestone dates for this project multiple times since the initial application. It also noted that a functional specification revision delayed ATCO Electric's PPS submission, which further delayed the facility application submission. As a result, the ISD for the Thickwood project cannot be accurately forecast. FTI was also of the opinion that the forecast expenditures for the test period are of questionable validity in light of continuing schedule uncertainty and the under-spend in 2015 compared to forecasts contained in the O&U filing. FTI assumed that only facility application costs would be incurred in 2016 and noted that, historically, 1.6 per cent of total project costs have been allocated to facility applications. Consequently, FTI recommended that the forecast capital expenditures for 2016 be reduced to $2.6 million and that the previously forecast capital expenditures of $28.4 million in 2016 be deferred to 2017.[705]

945. In rebuttal, ATCO Electric stated that the relevant PPS and facility application had been submitted and that costs for 2016 should not be reduced to cover only the facility application. ATCO Electric submitted that the forecast for 2016 should be revised to $30.1 million to cover costs to procure line and substation materials including milestone payments for the MVar Static Var System; detailed engineering labour costs including geotechnical assessment; and owners costs including hearing and land right easement costs, project management, and planning and overhead costs. Forecast costs for 2017 are required to procure additional materials; cover line labour costs including completion of site preparation and survey, foundation work and partial completion of tower assembly; and substation labour costs including site preparation and survey. ATCO Electric stated that costs should not deferred and should be increased in the compliance

700 Transcript, Volume 9, pages 1570-1572.
701 Exhibit 20272-X1218, PDF page 5.
702 Transcript, Volume 9, page 1579.
703 Transcript, Volume 7, pages 1130-1131.
704 Exhibit 20272-X1297, RPG argument, PDF page 160.
705 Exhibit 20272-X0784, FTI evidence, PDF pages 83-86.

filing to align with the PPS and a quicker than anticipated hearing date for the facility application.[706]

946. In argument, ATCO Electric acknowledged that the proceeding for the Thickwood project facility application was suspended due to the Fort McMurray wildfire. Given this suspension, ATCO Electric proposed to again update the timing of its forecast expenditures in the compliance filing.[707]

Commission findings

947. As previously stated in this decision, the Commission considers that the best available information should be used where possible. ATCO Electric initially proposed to update its capital expenditure forecasts in the compliance filing to align with the PPS estimate. The proposal was partially based on a schedule which forecast a June 2016 oral hearing for the facility application for this project, with P&L being issued in October 2016.[708]

948. The oral hearing for the Thickwood Hills Development project is scheduled to take place concurrently with Alberta Powerline's Fort McMurray West 500-kV Transmission project and AltaLink's Sunnybrook 510S Upgrade project. This joint proceeding oral hearing is currently scheduled to begin on September 19, 2016.[709] The project schedule provided in the facility application assumed the P&L would be issued by December 2016.[710] Given the revised schedule for the facility application, it is no longer reasonable to expect the P&L to be issued by year-end 2016. As the evidence on the record is that construction was expected to begin following receipt of P&L,[711] this delay will necessarily affect the accuracy of the test period forecasts.

949. The Commission directs ATCO Electric to update its forecast capital expenditures and total project cost forecast in the compliance filing, to align with the PPS estimate for this project, while also accounting for the delay in the facility application proceeding.

11.4.1.1.11 56767 – Tinchebray 972S Breakers and Bus Work

950. The Tinchebray 972S Breakers and Bus Work project (Project 56767) was to install circuit breakers and complete bus work at Tinchebray 972S substation as part of the Vermilion-Red Deer and Edgerton-Provost 240-kV Transmission Development (VREPTD) program. Tinchebray is located approximately 150 km east of Red Deer. ATCO Electric submitted a business case for the 56767 project.[712]

951. The business case showed the total forecast cost of the project to be $11.4 million. The updated applied-for capital expenditure for project 56767 is $0.3 million in 2016 and $2.0 million in 2017, with no capital additions for the 2015-2017 test period.

952. The updated business case[713] and updated schedule of direct assigned projects both forecast an in-service date of April 2019, and described the current project stage as "pre-PPS

[706] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 36-38.
[707] Exhibit 20272-X1298, ATCO Electric argument, PDF pages134-135.
[708] Exhibit 20272-X1120, PDF pages 36-37.
[709] Proceeding 21030, Exhibit 21030-X1097.
[710] Proceeding 21030, Exhibit 21030-X0196, PDF page 23.
[711] Transcript, Volume 9, page 1570.
[712] Exhibit 20272-X0078.
[713] Exhibit 20272-X1104, PDF pages 161-165.

planning." The update removed all capital expenditures originally forecast for 2015 ($0.2 million), reduced 2016 from $1.5 million to $0.3 million, and reduced 2017 from $3.7 million to $2.0 million.[714]

953. The application stated that the VREPTD program was being deferred based on the November 23, 2015 AESO Long-Term Transmission Plan.[715]

Commission findings

954. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including changes to the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The new forecast start date for project 56767 is approximately one year later than initially estimated, and lower overall spending levels are anticipated once the project resumes. The Commission considers it reasonable to expect that the project may be delayed longer than one year, and, in any event, the continued economic weakness being experienced in Alberta may lead to a reassessment of the VREPTD as a whole. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove forecast capital expenditures associated with this project, for the purposes of determining revenue requirement, and to reflect the impacts of the removal in its compliance filing.

11.4.1.1.12 56768 – 9LX02 Boundary – Tinchebray

955. ATCO Electric submitted a business case for the 9LX02 Boundary – Tinchebray project (Project 56768).[716] The project was to construct approximately 67 km of single-circuit 240-kV transmission line from Tinchebray 972S Substation to ATCO Electric's service boundary with AltaLink and add four 240-kV breakers to Tinchebray 972S substation. Tinchebray is located approximately 150 km east of Red Deer.

956. The business case identified the total forecast cost of the project to be $112.7 million. The updated applied-for capital expenditure for project 56768 is $0.3 million in 2016 and $1.3 million in 2017 with no capital additions for the 2015-2017 test period.

957. The updated business case[717] and updated schedule of direct assigned projects both forecast an in-service date of April 2019 and described the current project stage as "pre-PPS planning." The update removed all capital expenditures originally forecast for 2015 ($1.8 million), reduced 2016 from $16.2 million to $0.3 million, and reduced 2017 from $30.4 million to $1.3 million. The updated forecast also showed the actual capital expenditure for 2014 was $0, and not $0.2 million as previously forecast.[718]

958. The application stated that the VREPTD program was being deferred based on the November 23, 2015 AESO Long-Term Transmission Plan.[719]

[714] Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[715] Exhibit 20272-X1099, revised application – blackline, PDF page 134.
[716] Exhibit 20272-X0079.
[717] Exhibit 20272-X1104, PDF pages 166-171.
[718] Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[719] Exhibit 20272-X1099, revised application – blackline, PDF page 134.

Commission findings

959. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including changes to the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The new forecast start date for project 56768 is approximately one year later than initially estimated, and lower overall spending levels are anticipated once the project resumes. The Commission considers it reasonable to expect that the project may be delayed longer than one year, and, in any event, the continued economic weakness being experienced in Alberta may lead to a reassessment of the VREPTD as a whole. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove forecast capital expenditures associated with this project, for the purposes of determining revenue requirement, and to reflect the impacts of the removal in its compliance filing.

11.4.1.1.13 5XXX2 – New Drury 2007S, 5XXX3 – New 7L65 In/Out to Drury and 5XXX4 – New 7L129 In/Out to Drury

960. The New Drury 2007S, New 7L65 In/Out and New 7L129 In/Out projects were added to ATCO Electric's forecast capital costs for the test period in its application update filed on February 23, 2016. These projects are part of the VREPTD program. In the revised application, ATCO Electric stated that significant portions of the VREPTD program have been deferred.[720] In the hearing, ATCO Electric's witness clarified that the AESO has filed a cancellation letter for the entire VREPTD program, however, ATCO Electric's witness Mr. Vachon stated that "[ATCO Electric] still expects, based on the discussions we have with the AESO, to see some form of upgrade in that area in alignment with what was originally proposed. The nature of which is still being studied and the timing of which as well."[721] The VREPTD program was proposed to improve system stability in the area. The projects collectively consist of construction of a new substation, Drury 2007S, and 6.5 km of 144-kV transmission line in in/out configurations connected to the new substation.[722]

961. All three projects were listed in a letter from the AESO to ATCO Electric which was submitted as an attachment to the revised application. The letter contains a schedule of transmission capital expenditures for the 2015-2017 period and states that the projects are "reasonable as per ATCO's [comments] and business case."[723]

962. All three projects are in the pre-PPS planning stage and have ISDs of April 1, 2019.

963. The New Drury 2007S Substation is forecast to cost a total of $19.7 million, of which $1.7 million in capital expenditures is forecast for the test period ($0.3 million in 2016 and $1.3 million in 2017).

964. The New 7L65 In/Out to Drury is forecast to cost a total of $1.9 million, of which $0.7 million in capital expenditures is forecast for the test period ($0.3 million in 2016 and $0.4 million in 2017).

[720] Exhibit 20272-X1100, revised application – clean, PDF page 139.
[721] Transcript, Volume 9, page 1541.
[722] Exhibit 20272-X1105, PDF pages 319-327.
[723] Exhibit 20272-X1100, revised application – clean, Attachment 10.3, PDF page 205.

965. The New 7L129 In/Out to Drury is forecast to cost a total of $2.5 million, of which $0.7 million in capital expenditures is forecast for the test period ($0.3 million in 2016 and $0.4 million in 2017).

966. The forecast capital expenditures in the test period are required for planning and engineering.[724]

967. None of these projects, nor their late inclusion in ATCO Electric's application, were addressed in any party's argument or reply argument.

Commission findings

968. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The Commission expects that the continued economic downturn in Alberta may lead to a reassessment of the VREPTD as a whole. The New Drury and In/Out to Drury projects are a reflection of ATCO Electric's expectations of the changes to the VREPTD program and the upgrades which will be required in the area to provide system stability. The AESO, however, has not provided clear direction to ATCO Electric regarding the requirements and timing of projects in the area. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, it is not reasonable to include these projects in the revenue requirement. ATCO Electric is directed to remove forecast capital expenditures in 2016 and 2017 for these projects, for the purposes of determining revenue requirement, in the compliance filing and to reflect the impacts of the removal in its compliance filing.

11.4.1.1.14 5XXX7 – 7L113 Rebuild

969. The 7L113 Rebuild project was added to ATCO Electric's forecast capital costs for the test period in its application update filed on February 23, 2016. The project was described as a response to the November 23, 2015 AESO Long-Term Transmission Plan, and was proposed to alleviate thermal constraints on the existing 7L113 between Ring Creek and Arcenciel substations. The project consists of reconductoring approximately 100 km of 144-kV line to increase capacity, and replacing line structures as required.

970. The project is in the pre-PPS planning stage and has an ISD of December 1, 2020.

971. The project is forecast to cost a total of $44.5 million, of which $4.5 million in capital expenditures is forecast for the test period[725] ($0.5 million in 2016 and $4.0 million in 2017).[726]

972. This project was listed in a letter from the AESO to ATCO Electric which was submitted as an attachment to the revised application. The letter contains a schedule of transmission capital expenditures for the 2015-2017 period and states that the projects are "reasonable as per ATCO's [comments] and business case."[727]

973. Neither this project, nor its late inclusion in ATCO Electric's application, was addressed in any party's argument or reply argument.

[724] Exhibit 20272-X1105, PDF pages 319-327.
[725] Exhibit 20272-X1105, PDF pages 334-336.
[726] Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[727] Exhibit 20272-X1100, revised application – clean, Attachment 10.3, PDF page 205.

Commission findings

974. The Commission has reviewed the November 2015 AESO Long-Term Transmission Plan which was cited in support of this project, and cannot find a direct reference to this line rebuild. The plan does state that "the existing 144-kV line from the Arcenciel substation to the Keg River substation may need to be rebuilt to a higher capacity in the long term because the above-mentioned near-term developments would not have occurred."[728] The Commission considers that the existence of a single indirect reference to the project in the AESO Long-Term Transmission Plan is insufficient to support a finding that the forecast capital expenditures for this project are reasonable and should be included in ATCO Electric's revenue requirement. ATCO Electric is directed to remove the forecast capital expenditures for this project, for the purposes of determining revenue requirement, in the compliance filing.

11.4.1.2 Customer projects

11.4.1.2.1 51181 – Carmon Creek Cogen

975. ATCO Electric submitted a business case for the Carmon Creek Cogen project (Project 51181).[729]

976. Project 51181 relates to the construction of approximately 23 km of new 240-kV transmission lines from the existing Wesley Creek substation to the new Brock 232S substation and expansion of the Wesley Creek substation pad. The project is driven by a System Access Request to develop the 690 megawatt (MW) Carmon Creek cogeneration project in the Peace River area.

977. The business case showed the total forecast cost of the project to be $46.3 million. The updated applied-for capital expenditure for the project is $5.7, $6.7 and $24.8 million in each of 2015, 2016 and 2017, respectively with a $46.2 million capital addition in 2017. The project had previously forecast capital expenditures in 2013 and 2014 of $0.5 million and $8.6 million, respectively.

978. The business case forecast an in-service date of July 2015. The update reduced capital expenditures in 2015 from $40.5 million to $5.7 million and pushed back the forecast in-service date to 2017.[730]

Commission findings

979. The Commission finds that given the current economic climate in Alberta, particularly the significant decline in the price of oil over the past two years, the uncertain future of the associated cogeneration facility and the fact that the customer has already placed this project on hold, it is very unlikely that this project will resume as forecast. Therefore, it is not reasonable to include costs for project completion in 2017. ATCO Electric is directed to remove 2017 capital expenditures and additions for Project 51181, for the purposes of determining revenue requirement, in the compliance filing.

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[728] AESO 2015 Long-Term Transmission Plan, released November 23, 2015, page 50, retrieved from: http://www.aeso.ca/downloads/2015_Long-termTransmissionPlan_WEB.pdf.
[729] Exhibits 20272-X0142 to 20272-X0146.
[730] Exhibit 20272-X1105, PDF pages 11-15.

11.4.1.2.2 53034 – Ksituan River 754S Capacity Upgrade

980. ATCO Electric submitted a business case for the Ksituan River 754S Capacity Upgrade project (Project 53034). This project was added to the application in the O&U filing.[731] The revised business case was submitted with the revised application on February 23, 2016.

981. Project 53034 was to add one 144/25-kV transformer at Ksituan River 754S substation. The project is driven by forecast load growth of 12.2 MW (from approximately 26 MW to 38 MW) at the Ksituan River 754S substation between 2015 and 2017. This will exceed the existing transformer's capacity in 2018.

982. The project is in the pre-PPS planning stage and has an ISD of May 1, 2018.

983. The project is forecast to cost a total of $3.9 million, of which $2.9 million in capital expenditures is forecast for the test period[732] ($0.1 million in 2015, $0.5 million in 2016, and $2.3 million in 2017).[733]

984. This project was listed in a letter from the AESO to ATCO Electric which was submitted as an attachment to the revised application. The letter contains a schedule of transmission capital expenditures for the 2015-2017 period and states that "no costs received – reasonable."[734]

985. In response to an IR, ATCO Electric acknowledged that there is no contribution for this project because the "investment exceeds cost."[735]

986. In response to another IR, ATCO Electric provided a preliminary milestone schedule for the project which showed an ISD of July 1, 2017.[736]

987. This project was not addressed in any intervener's evidence, argument or reply argument.

Commission findings

988. The Commission has reviewed the proposed schedule for this project. The project ISD was determined by the AESO in consultation with the customer(s).

989. The forecast ISD appears to have been revised from the milestone schedule originally proposed by ATCO Electric in meetings with the AESO, which was submitted in response to an IR. The Commission notes that several milestones were planned for completion prior to the application update on February 23, 2016.[737] Given that no additional documentation was submitted at that time, it is unclear whether this project is on schedule and can be completed as originally planned. The Commission finds that there is significant scheduling uncertainty associated with this project.

990. The Commission also finds that, given the current economic climate in Alberta, particularly the significant decline in the price of oil over the past two years, and the early stage of the project, there is no indication that this project will proceed as forecast. Therefore, it is not

[731] Exhibit 20272-X0573.
[732] Exhibit 20272-X1105, PDF pages 302-304.
[733] Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[734] Exhibit 20272-X1100, revised application - clean, Attachment 10.3, PDF page 206.
[735] Exhibit 20272-X0620, AET-AUC-2015OCT16-024(b) Attachment 1, PDF page 175.
[736] Exhibit 20272-X0620, AET-AUC-2015OCT16-021(b), PDF page 66.
[737] Namely, the connection proposal, functional specification and PPS direction should have been completed.

reasonable to include this project in the revenue requirement. ATCO Electric is directed to remove forecast capital expenditures, for the purposes of determining revenue requirement, in the compliance filing.

991. Any capital expenditure amounts for 2015 are actuals and, consistent with the Commission's finding in Section 11.1.2 above, there is a preference for the best available information, which is actual costs. Given that 2015 capital expenditures represent actual amounts, 2015 capital expenditures for this project are approved as filed for the purposes of determining the 2015 revenue requirement.

11.4.1.2.3 54020 - Muir POD (Point of Delivery) Substation

992. ATCO Electric submitted a business case for the Muir POD Substation project (Project 54020). The business case consisted of an email confirming the market participant wished to proceed with stage 1 and 2 of the AESO connection process, and a two page summary of a December 2015 meeting. A project cost estimate or forecast was not provided nor was a schedule. The meeting minutes indicated that the in-service date may slide to March 2018 if a 2016/2017 winter construction window is missed.[738]

993. The forecast capital expenditure for project 54020 is $0.2 million in 2015, $2.0 million in 2016, and $6.2 million in 2017, with no capital addition forecast for the 2015-2017 test period.[739]

Commission findings

994. The Commission finds there is insufficient information on the record to allow it to determine whether the forecast magnitude and timing of capital expenditures for the proposed project are reasonable. The record likewise provides no indication of the likelihood that the project will be undertaken at all. Based on the limited information available to it, and the apparent very early stage of the project, the Commission finds a more reasonable forecast expenditure level is one that reflects the preparation of a facility application, rather than the start of construction. ATCO Electric is directed to reduce Project 54020 capital expenditures in 2016 and 2017 to $0.2 million for each year in the compliance filing.

11.4.1.2.4 54156 – Aspen 240-kV Line and Substation

995. ATCO Electric submitted a business case for the Aspen 240-kV line and substation project (Project 54156).[740] The business case confirmed that the construction scope of the project was not yet finalized, but that it would include a new POD substation to be called Aspen, along with approximately 10 km of transmission line to connect it to the Alberta Interconnected Electric System (AIES), and upgrades to the existing Black Fly substation. The new voltage of the planned Aspen substation, either 144 kV or 240 kV, was not finalized in the plan.

996. The business case identified the project as being in the pre-PPS planning stage. Neither any cost estimates (including OOM, NID or PPS class) nor the functional specification were available at the time the business case was prepared. The business case stated the planned in-service date for this project is April 1, 2017.

[738] Exhibit 20272-X0952.
[739] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[740] Exhibit 20272-X0049.

997. The total forecast project cost is $35.0 million. The forecast capital expenditure for project 54156 is $5.0 million in 2016, and $30.0 million in 2017, with $35.0 million in capital additions forecast for 2017.[741]

998. In response to an IR, ATCO Electric provided a project milestone schedule showing a forecast PPS submission date of December 1, 2015, a facility application submission date of February 1, 2016, and the receipt of P&L by October 1, 2016.[742] The PPS and facility application were not available at the time of the final application update on February 23, 2016.[743]

Commission findings

999. This project is currently in the very early stages of its execution. The Commission considers it unlikely that it will be completed in 2017. While the project schedule on the record shows that the project is delayed, there is no evidence to suggest that this project will not proceed during the test period. The Commission finds it reasonable to conclude that early project milestones, such as regulatory approvals, could be achieved in 2016, leading to the start of construction as early as 2017. ATCO Electric is directed to reduce Project 54156 capital expenditures in 2016 and 2017 by 90 per cent each year and to remove the forecast capital additions, for the purposes of determining revenue requirement, in the compliance filing. In the Commission's view, limiting costs to those associated with planning and preliminary engineering, regulatory, procurement and preliminary construction activities reflects a reasonable forecast for capital expenditures in the test period. It also accounts for delays in the schedule that suggest construction of this project is unlikely to begin until late 2017, with completion occurring in the next test period.

11.4.1.2.5 55655 - Bohn POD (Point of Delivery) Substation

1000. ATCO Electric did not submit a business case for the Bohn POD Substation project (Project 55655).

1001. Project 55655 is considered to be part of ATCO Electric's Pipeline Transmission Development program.[744] Project 55655 had an actual in-service date of May 1, 2014.[745] The forecast capital expenditures for project 55655 are $0.5 million in 2015, and $0.4 million in 2016, with forecast capital additions of $0.5 million in 2015, and $0.4 million in 2016.[746]

1002. This project was listed in a letter from the AESO to ATCO Electric which was submitted as an attachment to the revised application. The letter contains a schedule of transmission capital expenditures for the 2015-2017 period and states that the project is "reasonable."[747]

Commission findings

1003. There is no information on the record of this proceeding that would enable the Commission to evaluate the reasonableness of the forecasts costs in the test period. This project was energized prior to the test period and, while some trailing costs are expected, it is not clear what work will be completed in the test period. The Commission is concerned that this project

741 Exhibit 20272-X1105, PDF pages 76-80.
742 Exhibit 20272-X1117, AET-AUC-2015DEC30-002(c) Attachment 5 revised.
743 Exhibit 20272-X1105, PDF page 79.
744 Exhibit 20272-X1100, revised application - clean, PDF page 138.
745 Exhibit 20272-X0738, AET-AUC-2015DEC30-002(a) Attachment 1.
746 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
747 Exhibit 20272-X1100, revised application – clean, Attachment 10.3, PDF page 206.

was energized sufficiently long ago that trailing costs would be expected to be negligible by now. The trailing costs for this project will be included in a future DACDA application where the prudence of those costs will be evaluated. The Commission expects that ATCO Electric will provide sufficient documentation in a DACDA to justify the requested additions.

1004. The Commission finds there is insufficient information on the record of this proceeding for it to approve the forecast costs for this project. Accordingly, the Commission directs ATCO Electric to reduce Project 55655 capital expenditures and additions in 2016 to $0 in the compliance filing.

1005. Given that 2015 capital expenditures represent actual amounts, 2015 capital expenditures for this project are approved as filed for the purposes of determining the 2015 revenue requirement.

11.4.1.2.6 55750 – Dover West Leduc

1006. ATCO Electric submitted a business case for the Dover West Leduc project (Project 55750).[748]

1007. Project 55750 relates to the construction of approximately 10 km of single-circuit 240-kV transmission line from Ells River 2079S substation to the Stone 2020S substation (which is customer-owned), and the addition of one 240-kV circuit breaker at the Ells River 2079S substation. The project is driven by a customer request to connect a thermal-assisted gravity drainage facility northwest of Fort McMurray to the AIES.

1008. The business case showed the total forecast cost of the project to be $19.2 million, of which $16.6 million would be customer contributed cost. The updated applied-for capital expenditure for project 55750 is $0.3 million in 2017, with no capital additions for the 2015-2017 test period. The project had previously forecast capital expenditures in 2012, 2013 and 2014 of $0.1 million, $0.2 million, and $0.3 million, respectively.[749]

1009. The business case forecast an in-service date of July 2017. The update[750] removed all capital expenditures originally forecast for 2015 ($0.6 million) and 2016 ($10.4 million), and reduced 2017 capital expenditures from $7.6 million to $0.3 million due to a revised in-service date of July 2019.

Commission findings

1010. The project is not forecast to incur costs until 2017 and is driven by a need to connect a new oil sand recovery facility.

1011. The Commission finds the following considerations raise significant doubts that this project will experience material, if any, progress during the test period: (1) the continued weakness in Alberta's economy including, especially, the reduced level of activity in Alberta's petroleum sector; (2) this project is still in its early stages; (3) the originally projected ISD has already been deferred by two years; and (4) the project's sole customer has frozen its capital expenditures. Therefore, it is not reasonable to include this project in approved capital

[748] Exhibit 20272-X0068.
[749] Exhibit 20272-X1101 Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[750] Exhibit 20272-X1104, PDF pages 141-146.

expenditures. ATCO Electric is directed to remove the associated forecast capital expenditures for the purposes of determining revenue requirement in the compliance filing.

11.4.1.2.7 56655 – AltaGas Kent Generator – Central East

1012. ATCO Electric submitted a business case for the AltaGas Ken Generator – Central East project (Project 56655) the purpose of which is to connect a customer power plant to the transmission system. Specifically, the scope of work is to construct a new switching substation, to be called Morrison 2051S, and approximately 1.5 km of 144-kV transmission line.

1013. The project is currently in the pre-PPS stage. The forecast ISD for this project was revised by one year to June 2017 in the application update filed on February 23, 2016.[751]

1014. The updated business case reduced the total forecast project cost from $18.3 million to $13.7 million. The forecast capital expenditures for project 56655 are $0.6 million in 2015, $1.7 million in 2016, and $11.5 million in 2017, with $13.7 million in capital additions forecast for 2017.[752]

Commission findings

1015. On February 16, 2016, the Commission issued Decision 21307-D01-2016[753] which granted a time extension for the Kent power plant until May 2018. Decision 21307-D01-2016 stated that "hydrogeologic field investigation[s have] yet to be conducted and the related environmental approvals have not been issued" and that AltaGas had indicated it would need additional time to evaluate potential impacts of the Climate Leadership Plan to reassess its investment in the project.

1016. The Commission finds that, with the Kent power plant not yet under construction and its economic and hydrogeologic feasibility still being assessed, it is not reasonable to forecast Project 56655 to be in-service by 2017. ATCO Electric is directed to remove forecast capital expenditures and additions for Project 56655, for the purposes of determining revenue requirement, in the compliance filing.

11.4.1.2.8 56865 – Mainstream Wainwright

1017. ATCO Electric submitted a business case for the Mainstream Wainwright project (Project 56865) to connect a wind power facility to the AIES. This project is included in the VREPTD.[754] With the deferral of the VREPTD program, the scope and forecast cost were updated and the majority of work was moved into AltaLink Management Ltd.'s service territory. ATCO Electric's updated scope for the project includes remedial action scheme changes that are forecast to cost $0.3 million. The forecast in-service date of March 2017 was not changed in the final application update on February 23, 2016 to account for the change in scope of work.[755]

[751] Exhibit 20272-X1105, Attachment 4 – Revised Business Cases – Clean, PDF pages 174-175.
[752] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[753] Decision 21307-D01-2016: AltaGas Holdings Inc., Time Extension to Power Plant Approval 3547-D02-2015, Proceeding 21307, Application 21307-A001, February 16, 2016.
[754] Exhibit 20272-X1100, revised application – clean, PDF page 139.
[755] Exhibit 20272-X1105, Attachment 4 – Revised Business Cases – Clean, PDF page 199

1018. The forecast capital expenditures and capital additions for project 56865 are each $0.3 million in 2017.[756]

1019. In the hearing, ATCO Electric's witness, Mr. Vachon, stated that AltaLink had started work on its portion of the project and that project managers from ATCO Electric and AltaLink would be working together closely to ensure alignment of activities to be completed by the respective project teams. Execution of ATCO Electric's portion of this project is not required until AltaLink has completed its project work.[757]

1020. In response to an undertaking, ATCO Electric provided an update on the status of the project wherein the ISD was revised to Q3 2018. In that same response, ATCO Electric noted that the PPS estimates from ATCO Electric and AltaLink are due in October 2016.[758]

Commission findings

1021. The VREPTD program was deferred and its scope was modified because of the downturn in Alberta's economy, as reflected in the November 2015 AESO Long-Term Transmission Plan. Given the uncertainty in the project schedule and the interdependence of ATCO Electric's scope of work with that to be completed by AltaLink, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove the forecast capital expenditures and capital additions for Project 56865, for the purposes of determining revenue requirement, in the compliance filing.

11.4.1.2.9 58215 – Sharp Hills Wind Farm

1022. ATCO Electric submitted a business case for the Sharp Hill Wind Farm project (Project 58215) to construct a 240-kV substation and associated 240-kV transmission line connecting the new substation to existing line 9L46 between Pemukan 932S and Lanfine 959S substations. The project is to connect a 300 MW wind power facility.

1023. Due to the early stage of the project a detailed cost estimate was not submitted.[759]

1024. The total forecast cost of the project was $20.0 million. The planned capital expenditure for the project is $1.0 million in 2017 with no capital additions for the 2015-2017 test period. The planned in-service date is April 1, 2018. At the time of original filing, the forecast capital expenditures were $0.2 million in 2016 and $4.0 million in 2017.

Commission findings

1025. The project is not expected to begin incurring costs until 2017, and is driven by a need to connect a wind power facility.

1026. The Commission finds that given the current economic climate in Alberta, low wholesale electricity market prices, lower than expected load growth, and the early stage of execution for this project, it is not reasonable to include this project in the utility's revenue requirement for the test years. ATCO Electric is directed to remove forecast capital expenditures for Project 58215, for the purposes of determining revenue requirement, in the compliance filing.

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[756] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
[757] Transcript, Volume 9, page 1543.
[758] Exhibit 20272-X1217.
[759] Exhibit 20272-X1104, PDF pages 219-221.

11.4.1.2.10 58562 - Hand Hills Wind Project and 58569 – Hand Hills Wind Power Facility

1027. ATCO Electric submitted business cases for the Hand Hills Wind and Hand Hills Wind Power Facility projects (projects 58562 and 58569).

1028. Project 58562 relates to the construction of approximately 17 km of 240-kV single-circuit transmission line from Coyote Lake 963S Substation to Highland 572S Substation and expansion of the Coyote Lake 963S Substation. Project 58569 is for the construction of a new 240-kV switching station to be called Mother Mountain 2055S and a 240-kV transmission line from Mother Mountain 2055S substation to the customer-owned Hand Hills 605S Substation. The projects are inter-related and are required to connect adjacent wind farms to the AIES.

1029. The planned capital expenditure for project 58562 is $8.4 million in 2017 with no capital additions for the 2015-2017 test period. The planned capital expenditure for Project 58569 is $6.0 million in 2017 with no capital additions for the 2015-2017 test period. The capital expenditures in 2014 were $0.7 million and $0.5 million, for projects 58562 and 58569, respectively.

1030. The business case for Project 58562 included progress reports. Initial reports from 2011 to 2013 showed in-service dates being pushed back throughout 2013. Later progress reports in 2013 reflected 2014 in-services dates. The September 2014 progress report showed a forecast in-service date of October 2016.

1031. The submitted business case for project 58569 also included progress reports. Initial reports from 2011 and 2012 showed in-service dates of December 2013. Later progress reports omitted a forecast in-service date until June 2014 when a revised planned in-service date of February 2015 first appeared. The September 2014 progress report showed a forecast in-service date of October 2016.

1032. The business cases for the projects identified April 1, 2017 as the forecast in-service date. The updated business case, filed with the final application update on February 23, 2016, showed an expected in-service date of December 31, 2018.

Commission findings

1033. These projects are not expected to begin incurring costs until 2017, and are driven by the need to connect wind power facilities.

1034. The Commission finds that given the economic climate in Alberta, low wholesale electricity market prices, lower than expected load growth, and the history of significant and recurring delays on projects 58562 and 58569, it is not reasonable to include capital expenditures for these projects in revenue requirement. Supporting the Commission's conclusion is the fact that no update has been provided by ATCO Electric to an August 2015 progress report in respect of Project 58569, which stated that "[t]he project is currently on hold and the milestone schedule forecast will be updated once customer funding is received which impacts the project schedule."[760] ATCO Electric is directed to remove forecast capital expenditures for both projects, for the purposes of determining revenue requirement, in the compliance filing.

[760] Exhibit 20272-X0945, PDF page 188.

11.4.1.2.11 58923, 58924 and 58925 – Current Lake, Armitage and Cavendish Substations

1035. ATCO Electric submitted business cases for the Currant Lake, Armitage and Cavendish Substation projects (projects 58923, 58924 and 58925).[761]

1036. The three projects are all required to provide power to new TransCanada Keystone XL Pipeline pump stations.

1037. Project 58923 involves the construction of a new substation, to be called Currant Lake, adjacent to a customer pump station, and approximately 10 km of 144-kV transmission line to connect it to the AIES. The forecast capital expenditure for project 58923 is $0.2 million in 2016 and $0.2 million in 2017.

1038. Project 58924 involves the construction of a new substation, to be called Armitage, adjacent to a customer pump station, and approximately 12 km of 144-kV transmission line to connect it to the AIES. The forecast capital expenditure for Project 58924 is $0.2 million in 2016 and $0.3 million in 2017.

1039. Project 58925 involves the construction of a new substation, to be called Cavendish, adjacent to a customer pump station, and approximately 3.7 km of 144-kV transmission line to connect it to the AIES. The forecast capital expenditure for project 58925 is $0.3 million in 2016 and $0.3 million in 2017.

1040. There are no forecast capital additions for any of these projects in the 2015-2017 test period.

1041. The February 23, 2016 application update removed all forecast capital expenditures for these projects in 2015. All three projects have a revised forecast in-service date of October 2019.[762]

Commission findings

1042. The President of the United States of America denied a Presidential Permit for the construction of the Keystone XL pipeline on November 6, 2015. TransCanada launched a legal challenge to that denial on January 6, 2016.[763]

1043. Construction of the Keystone XL pipeline is the key driver for projects 58923, 58924 and 58925. Given the current status of the proposed pipeline and ATCO Electric's forecast suspension of all spending on these projects in 2015, it is not reasonable to include forecast expenditures resuming in 2016 and 2017. ATCO Electric is directed to remove projects 58923, 58924 and 58925 from its forecast capital expenditures, for the purposes of determining revenue requirement, in the compliance filing.

[761] Exhibits 20272-X0115 to 20272-X0122.
[762] Exhibit 20272-X1105, PDF pages 264-277.
[763] TransCanada Press Release: "TransCanada Commences Legal Actions Following Keystone XL Denial," released January 6, 2016, retrieved from http://www.transcanada.com/announcements-article.html?id=2014960&t=.

11.4.1.2.12 58965 – Heartland Pump Station

1044. ATCO Electric submitted a business case for the Heartland Pump Station project (Project 58965).[764]

1045. Project 58965 relates to the construction of a new substation (Vincent 2091S) adjacent to a customer pump station, a 144-kV transmission line required to connect it to the AIES, and the addition of a capacitor bank to the Irish Creek 706S substation. The project is required to provide power to a new TransCanada Heartland Pipeline pump station.

1046. The business case filed with the original application forecast a total project cost of $14.1 million, with $5.1 million being a customer contribution. The forecast capital expenditure for project 58965 is $0.2 million in 2015, $6.8 million in 2016, and $8.4 million in 2017, with a $16.0 million capital addition forecast for 2017. The updated forecast in-service date is November 2017.

1047. The February 23, 2016 application update reduced the forecast capital expenditure in 2015 from $1.0 million to $0.2 million, increased the capital expenditure in 2016 from $4.6 million to $6.8 million, and increased the capital expenditure in 2017 from $7.9 million to $8.4 million.[765]

Commission findings

1048. The Commission finds that various factors affect the reasonableness of the forecast ISD in the business case for this project. Alberta is currently facing a challenging economic climate that is made all the more uncertain by a sustained period of low oil prices. The Commission finds that given these factors, it is not reasonable to include this project in the utility's revenue requirement for the test years. ATCO Electric is directed to reduce Project 58965 capital expenditures in 2016 and 2017 to $0.2 million and remove the forecast capital additions, for the purposes of determining revenue requirement, in the compliance filing.

11.4.2 Non-direct assigned and capital maintenance projects

1049. ATCO Electric explained in its application that it has a legislated responsibility to maintain the safety and integrity of its assets. As transmission assets age, wear out or no longer meet required functionality, an investment plan must be developed for the asset or group of assets. This plan can comprise any, or a combination of, the following:

- initiate a capital maintenance project to extend the life of the asset
- perform preventive, corrective or emergency repairs, and/or
- initiate a capital maintenance project to upgrade or replace the asset(s)

1050. ATCO Electric submitted that it was implementing ISO 55001 asset management principles to achieve a holistic and effective asset management system. The utility explained that this approach reviews asset status and performance through its entire life cycle from "cradle to the grave," and consists of the following phases:

- asset planning
- asset installation (engineering, construction and commissioning)

[764] Exhibit 20272-X0123.
[765] Exhibit 20272-X1105, PDF pages 278-283.

- asset operation
- asset maintenance (improvements and/or replacements)
- reclamation

1051. ATCO Electric submitted that its Transmission Capital Maintenance (TCM) program enabled asset maintenance activities, which are funded from capital investment. The TCM program was designed to:

- manage transmission assets in accordance with life cycle asset strategies
- prioritize asset replacement and maintenance requirements through capital investment

1052. ATCO Electric explained the main drivers for transmission capital maintenance projects as follows:

> Major drivers for TCM projects are diverse and stem from requirements which include: preserving the continuity of electrical service to the public; eliminating or minimizing hazards to employees, the general public and the environment; meeting legal and regulatory requirements, all while using company resources efficiently. These drivers can be classified into four primary classes.
>
> - Safety/Environment: This project driver relates to managing hazards and risks to employees, the general public and the environment.
>
> - Regulatory: This driver enables ATCO Electric to meet regulatory requirements. These regulatory requirements are often intended to protect public safety or preserve the electric system integrity.
>
> - Technical: This driver enables ATCO Electric to manage asset risks. The risks could arise from reliability, asset condition, asset compatibility issues, capacity increase, performance improvement and emergency restoration.
>
> - Productivity: This driver relates to projects that enhance productivity or provide economic savings.[766]

1053. The following ATCO Electric table summarizes TCM program expenditures including 2012-2014 actuals and forecasts for the 2015-2017 test years:

[766] Exhibit 20272-X1100, paragraphs 328-329, PDF pages 144-145.

Table 38. Transmission capital maintenance program forecast

	2012	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test period	Test period	Test period
	($ million)					
TCM – Substation Assets	24.6	23.0	28.7	40.1	46.1	56.7
TCM – Transmission Lines	7.2	4.3	17.3	26.6	29.8	10.7
Transmission Line Clearance Mitigation program	6.7	5.7	1.0	8.2	13.9	19.5
TCM – Transmission ROW	5.2	4.6	4.7	6.4	9.3	9.5
TCM – Telecommunications	8.2	15.8	10.4	17.0	25.2	18.1
System Improvements and Regulatory Compliance Programs (Cyber Security, Operational Information System)	(0.5)	1.2	1.4	0.7	0.9	1.1
TCM – Isolated Generation	5.5	5.3	2.4	2.8	4.2	3.9
Inflation adjustment				0.0	(1.1)	(2.7)
Total capital expenditures	**56.9**	**59.9**	**65.9**	**101.8**	**128.3**	**116.8**
Total capital additions	**43.9**	**51.9**	**58.1**	**127.7**	**145.9**	**116.2**

Source: Exhibit 20272-X1100, paragraph 354, PDF page 152.

1054. ATCO Electric provided business cases to support many of the projects identified in the categories above.

1055. Both the RPG and Calgary expressed concerns with the quality of the business cases provided, and the fact that not all projects were supported by business cases. The RPG focused on projects related to capital maintenance while Calgary focused on projects related to IT and asset management. The adequacy of ATCO Electric's business cases is discussed generally in Section 11.1.5 above and specifically, as it relates to capital maintenance business cases, in the section below.

1056. The Commission also discusses certain TCM projects in the subsections below.

11.4.2.1 Business cases

1057. The RPG argued that ATCO Electric had failed to carry out any cost/benefit analysis of alternatives for virtually all of the capital maintenance business cases they submitted to justify proposed expenditures. The RPG noted that the Commission had previously directed ATCO Electric to provide the costs and benefits of maintenance projects in its decision on ATCO Electric's 2013-2014 GTA.[767] The RPG also noted that only two of the provided business cases included a comparative cost analysis, and none provided any monetized assessment of the benefits the project would provide to ratepayers.[768]

1058. ATCO Electric stated that individual projects are analyzed for a cost-optimized implementation strategy and are prioritized using a risk-based ranking which considers both the probability of the event occurring and its associated impact. ATCO stated that "program prioritization based on risk is the only appropriate way to ensure the full suite of factors that drive TCM are appropriately considered and balanced."[769] The RPG argued that ATCO Electric's

[767] Decision 2013-358, for example in paragraph 284 related to maintenance activities.
[768] Exhibit 20272-X1297, RPG argument, paragraph 552, page 173.
[769] Exhibit 20272-X1120, 2016-02-23 AET rebuttal evidence, PDF page 117.

approach did not cover sufficient alternatives and that "[f]or the majority of capital maintenance projects, a TFO always has four basic alternatives which should be considered: risk control, repair, refurbish and replace." The RPG noted the MFR stipulate that the ATCO Electric business cases should include "[t]he incremental capital and operating costs associated with each alternative examined for a minimum 10-year period" and "[t]he annual costs of each alternative for the period analyzed."[770] It was the RPG's position that ATCO Electric should have provided a comparative cost analysis of at least these four basic alternatives for all of the capital maintenance business cases to satisfy the MFR.[771]

1059. The RPG submitted that ATCO Electric has continuously over-forecast its capital maintenance spending by an average of 36 per cent over the past five years. It asserted that ATCO Electric has not properly supported the need for each capital maintenance project in this GTA filing, as exhibited by the lack of cost analyses of alternatives in its business cases and by its use of a risk assessment process which significantly overstates the degree of risk posed by aging facilities.[772]

1060. The RPG argued that current ATCO Electric practices regarding risk assessment and business case development do not achieve a level of supply reliability that balances the cost of providing services with the value customers place on reliability of supply. The RPG was concerned that "the ATCO Electric capital maintenance business cases almost exclusively (1) justify the replacement of equipment on the basis of risk assessments which have no connection to the value of reliability, (2) include minimal or no analysis of alternatives, and (3) include no comparative cost or cost/benefit analysis." The RPG submitted that such deficiencies would result in a less than optimal prioritization of capital maintenance and would drive unnecessary costs.[773]

1061. One of the RPG's primary concerns with ATCO Electric's current "bottom up" budgeting approach for capital maintenance projects is that it ranks projects according to net benefit. It claimed that out of the 48 business cases ATCO Electric provided, only two included a comparative cost analysis, and none provided any monetized assessment of the benefits the project would provide to ratepayers.[774]

1062. Mr. Cline, a consultant with Grid Power Development and Design Inc., which provided evidence on behalf of the RPG, undertook to provide an example of what a comprehensive business case would look like and the kind of analysis it should include. He identified the need to (1) improve the risk analysis, (2) include at least four basic alternatives in all business cases, and (3) provide a comparative cost analysis of the alternatives. The RPG fully supported all of the changes and improvements identified in this undertaking.[775]

1063. The RPG's recommendations for business cases included the following:

- All business cases should include an evaluation of at least four base alternatives: risk control, repair, refurbish and replace. In broad terms these alternatives are:

[770] Bulletin 2006-25, PDF page 109.
[771] Exhibit 20272-X1297, RPG argument, paragraph 554, page 173.
[772] Exhibit 20272-X1297, RPG argument, paragraph 565, pages 176-177.
[773] Exhibit 20272-X1297, RPG argument, paragraph 690, page 206.
[774] Exhibit 20272-X1297, RPG argument, paragraph 691, pages 206-207.
[775] Exhibit 20272-X1297, RPG argument, paragraph 692, page 207.

ii. Risk Control: Operational practices or capital expenditures which will provide adequate control of the identified risks by reducing the impact or probability.
iii. Repair: Low cost onsite repairs which can be carried out to improve the health and delay the need for a refurbishment or replacement but do not necessarily provide a long term solution to the problem.
iv. Refurbish: An overhaul of the asset which provides a significant extension to the expected life; in the order of ten or more years.
v. Replace: Replace or rebuild the asset to a near new state.

- All business cases must include at least a comparative cost analysis of the four standard alternatives comparing the alternatives on the basis of how many years they will delay the need for a complete replacement of the asset in question.
- All business cases for projects being justified on the basis of customer service reliability and/or O&M efficiency improvements must include a cost/benefit analysis.[776]

1064. ATCO Electric stated that it only puts forward a business case where its risk prioritization shows an unacceptable level of risk and where continued preventative maintenance is no longer a reasonable alternative. ATCO Electric includes economic analysis in business cases where alternatives are compared.[777] In contrast, Mr. Cline stated that only in the specific case where completed studies show extremely high voltage levels that raise safety issues is it acceptable to not complete a cost/benefit analysis. Mr. Cline then went on to say:[778]

> But that having been said, there's quite a number of the ground grid improvements where the driver for the improvement is system expansion, which may or may not occur. So in that case, I think there is a cost-benefit study that could be performed where Option 1 would be we wait and see what happens, and if we can't get the ground grid improved before the system development occurs, then we switch to rubber glove work or take the consequence, so higher operating costs, until the repairs can be carried out, for example.
>
> So that's a longer answer. I'm trying to give you examples. But the problem with these programs is you've lumped a whole bunch of stuff into one program and then you just simply say there are no alternatives. But each on an individual-by-individual basis, I believe some have -- definitely have a cost-benefit- type alternative where you could take a higher operating cost in order to delay that capital.[779]
>
> …
>
> So I'm not -- when I wrote the reply to the response, I mean, I'm not -- I think you have to be pragmatic, and I agree with that, in that if it's a no-brainer don't waste your time. But in many cases, I think there is a cost-benefit analysis that could be performed so that you could examine, you know, what's my short-term operating labour costs as opposed to spending that capital now versus delaying it for three, four, five years.
>
> And, based on my experience, I think that's always a worthwhile exercise because it forces people to think about, you know, what is my ongoing cost that I am going to avoid

[776] Exhibit 20272-X1297, RPG argument, paragraph 700, pages 209-210.
[777] Exhibit 20272-X1298, ATCO Electric argument, PDF page 112.
[778] Exhibit 20272-X1307, RPG reply argument, paragraph 338, page 95.
[779] Transcript, Volume 13, page 2423, lines 6-24.

> as opposed to how much cost am I going to drive by simply replacing or refurbishing immediately at a much higher cost.[780] (emphasis added by RPG)

1065. The RPG argued that "[i]t is clear from Mr. Cline's complete response to questioning by ATCO Electric that Mr. Cline's position under questioning is entirely consistent with the Ratepayer Group's position 'that the TFOs have not complied with the intent of the MFR with regards to the development and cost analysis of alternatives.' As documented in the RPG's information response, out of the forty-eight business cases provided by ATCO Electric, only two provided a cost analysis."[781]

1066. ATCO Electric submitted that it had outlined the method used to evaluate when assets require replacement and/or maintenance in its application and that it employed industry recognized techniques for assessing the health of its assets. ATCO Electric further pointed out that it had outlined, in Section 10 of the application and in the business cases, that not all asset renewal decisions are related to asset condition. It explained that major drivers for TCM projects are safety and the environment, regulatory requirements, technical factors (including asset condition, reliability, vendor support, capacity increase) and productivity.[782]

1067. ATCO Electric argued that it had included economic analyses in business cases for projects that compare different alternatives for addressing identified risks. However, as ATCO Electric set out in its rebuttal evidence, the majority of the projects in its TCM programs were not readily assessable on this basis because the cost to customers of failures would vary widely depending on customer time, timing and usage profile. ATCO Electric argued that the RPG's assumption that an asset could continue to operate under preventative maintenance for a period of time is not valid and confirmed that it had only put forward business cases where risk prioritization showed an unacceptable (high) level of risk and where the "status quo" of continued preventative maintenance was not a reasonable alternative.[783]

1068. ATCO Electric took exception to the RPG characterization of project drivers and stated that the drivers for its TCM program "are diverse and stem from requirements which include: preserving the continuity of electrical service to the public; eliminating or minimizing hazards to employees, the general public and the environment; meeting legal and regulatory requirements, all while using company resources efficiently."[784]

1069. ATCO Electric also disputed the RPG's view of risk assessment stating the "RPG has misapplied the risk matrix from TransGrid's Risk Management Framework."[785] The utility further submitted in reply argument that "the RPG's assertion that a TFO always has at least four alternatives (risk control, repair, refurbish and replace) does not reflect the reality of the risks addressed by ATCO Electric's transmission capital maintenance programs." ATCO Electric argued that it only assesses viable alternatives in its business cases.[786]

1070. ATCO Electric also argued that the "RPG had narrowly focused its recommendations on the role reliability plays in the TCM Business Cases, without appropriately considering the very

[780] Transcript, Volume 13, page 2424, lines 5-19.
[781] Exhibit 20272-X1307, RPG reply argument, paragraph 339, pages 95-96.
[782] Exhibit 20272-X1298, ATCO Electric argument, paragraph 258, pages 103-104.
[783] Exhibit 20272-X1298, ATCO Electric argument, paragraph 261, pages 104-105.
[784] Exhibit 20272-X1298, ATCO Electric argument, paragraph 266, page 106.
[785] Exhibit 20272-X1298, ATCO Electric argument, paragraph 267, page 107.
[786] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 167, page 62.

real safety and environmental risks associated with catastrophic failures of energized transmission equipment." It claimed that the drivers for TCM projects are diverse; while reliability is one driver, it is not the only driver. ATCO Electric submitted it had outlined in detail the full suite of consequences of not proceeding with the recommended action in all the business cases it provided. It was of the view that there was no meaningful value to be derived from attempting to provide the kind of cost/benefit analysis advocated by the RPG. ATCO Electric argued that the scope and scale of assumptions required rendered such analysis meaningless and that its business cases provided sufficient justification for the requested amounts.[787]

11.4.2.2 Capital maintenance estimating accuracy

1071. The RPG considered ATCO Electric's forecast amounts for capital maintenance expenditures and additions to be too high for two reasons: (1) they significantly exceed ATCO Electric's actual historical expenditures and (2) in the past, ATCO Electric has shown a propensity to spend less (and often considerably less) than what it has applied for and what the Commission has approved. The RPG recommended that the Commission approve a cap on forecast capital maintenance expenditures and additions of $50.9 million in every year of the test period. Application of this cap would remove capital maintenance additions of $54.5 million in 2015, $90.0 million in 2016 and $60.5 million in 2017.

1072. The RPG submitted that, alternatively, if the Commission rejects a cap it should direct ATCO Electric to reduce its forecast of capital maintenance expenditures and additions by $44.4 million in 2015, $51.0 million in 2016 and $40.4 million in 2017 to reflect levels that are in line with historical spending. The RPG argued that such an adjustment would recognize ATCO Electric's past record of over forecasting and under spending on capital maintenance projects.

1073. The RPG also requested that the Commission immediately direct ATCO Electric to halt all work on Project 50940 – Transmission Double Circuit and on Project 50060 - Keg River Substation Rebuild, until such time as ATCO Electric can provide the necessary evidence to support the continued need for these projects.[788] These projects are discussed in sections 11.4.2.2.1 and 11.4.2.2.2 below.

1074. The RPG provided an analysis isolating additions related to capital maintenance and excluding other non-direct assigned capital additions, such as software and buildings, which it considered to have no bearing on, or relevance to, the capital maintenance program. From this analysis, the RPG derived historical five- and 10-year measures of forecasting accuracy for ATCO Electric's capital maintenance additions,[789] as illustrated in the following table:

[787] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 192, pages 72-73.
[788] Exhibit 20272-X1297, RPG argument, paragraph 11, summary point #8, pages 14-15.
[789] Exhibit 20272-X1297, RPG argument, paragraph 186, page 74.

Table 39. Capital maintenance: five- and 10-year historical forecasting accuracy

10-year totals and averages	
Total variance from applied for (10 years)	(163.6)
Total variance from approved (10 years)	(98.1)
Total % variance from applied for (10-year average)	(18.7%)
Total % variance from approved (10-year average)	(12.0%)
5-year totals and averages	
Total variance from applied for (5 years)	(153.6)
Total variance from approved (5 years)	(110.7)
Total % variance from applied for (5-year average)	(28.8%)
Total % variance from approved (5-year average)	(22.4%)

Source: Exhibit 20272-X1297, RPG argument, paragraph 186, page 74.

1075. From this analysis, the RPG determined that ATCO Electric's five- and 10-year historical applied-for forecasting accuracy for capital maintenance additions was -28.8 per cent and -18.7 per cent, respectively, and argued that forecasting accuracy for capital maintenance was significantly worse in the later years. For comparative purposes, the RPG noted that in the last two years, ATCO Electric's forecasting accuracy for capital maintenance additions has been 36 per cent.[790] The RPG argued that in all ranges of years, ATCO Electric's historical forecasting accuracy was very poor and getting worse with time.[791] The Commission notes that when the RPG refers to "forecasting accuracy" what it is actually referring to are the observed *variances* between ATCO Electric's past forecasts and actual expenditures.

1076. The RPG argued that, notwithstanding ATCO Electric's request for an increase in capital maintenance spending of 215 per cent compared to 10-year historical spending levels, it had provided no evidence of benefits to ratepayers to justify such a dramatic increase. The RPG submitted that ATCO Electric should be required to manage its planned capital maintenance spending, including all capital maintenance except for transmission line relocations, within the limits of a top down budget set at the inflation corrected 10-year average actual spending rate of $50.9 million per year. This recommendation was in addition to the RPG's request that ATCO Electric be directed to develop all forecasts of its FTEs and related support costs that may flow into capital maintenance expenditures using a zero-based budget.[792] Zero-based budgeting is discussed in Section 11.1.3 above.

1077. The RPG argued that "[b]y setting a ceiling on the total planned capital maintenance spending budget, ATCO Electric's capital maintenance management team will be required to rank and prioritize capital maintenance items in order to stay within the budget. ATCO Electric's non-direct assigned capital maintenance expenditures and additions should be reduced by the amounts provided below ... which then allows the forecast to match the inflation corrected ten-year average actual spending rate."[793] The RPG provided the following table:

[790] Exhibit 20272-X0789, RPG evidence, PDF page 117, Table 16.3-3.
[791] Exhibit 20272-X1297, RPG argument, paragraph 187 pages 74-75.
[792] Exhibit 20272-X1297, RPG argument, paragraph 539, page 168.
[793] Exhibit 20272-X1297, RPG argument, paragraph 540, pages 168-169.

Table 40. RPG recommended reduction to capital maintenance additions and expenditures

	2012	2013	2014	2015	2016	2017
	($ million)					
Capital maintenance additions	27.8	48.5	56.4	123.2	141.7	112.3
less line relocations				17.7	0.8	0.9
Planned capital maintenance additions				105.5	140.9	111.4
Recommended reduction				54.59	90.00	60.50
Capital maintenance expenditures	51.5	55.4	63.5	99.0	124.2	113.0
less line relocation				17.7	0.8	0.9
Planned capital maintenance expenditures				81.3	123.4	112.1
Recommended reduction				30.38	72.45	61.21

Sources: Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA Schedules-Revise Feb 23, 2016, Schedule 10-4; Exhibit 20272-X0130, PDF page 75, 7.0 Project Cost Estimate, Transmission Line Relocation.

1078. The RPG submitted that any increase to this budget ceiling should be justified by ATCO Electric in future GTAs through the mechanism of a full business case including a cost/benefit analysis. The business case should, at a minimum, include specific goals for the requested increase. Progress towards goals identified in the business case, such as the reduction of O&M expenditures or addressing deteriorating customer service reliability, could then be monitored to demonstrate that the expenditures carried out by ATCO Electric were cost effective.

1079. The RPG's recommendation was based on the following four perceived problems that it identified with the current ATCO Electric capital maintenance budget management and forecasting methodology:

> a. ATCO Electric has an established track record of over-forecasting and then significantly under-spending on capital maintenance.
> b. The outage rates of ATCO Electric's major equipment is already significantly below the Canadian average and therefore an increase in expenditures is not warranted for reliability purposes.
> c. ATCO Electric has failed to provide cost/benefit analysis to justify the proposed expenditures in the capital maintenance business cases.
> d. ATCO Electric has justified the majority of the capital maintenance on the basis of risk assessments which significantly overstate the degree of the risks being mitigated and which give no consideration to the cost/benefit of the proposed projects.[794]

1080. The RPG also provided the following table as an aid to cross[795] in support of its claim that, historically, ATCO Electric has exhibited a propensity to over-estimate additions. The table shows that, on average, over the 10-year period from 2005 to 2014, ATCO Electric spent 9.9 per cent less on additions than it had forecast.

[794] Exhibit 20272-X1297, RPG argument, paragraph 542, page 169.
[795] Exhibit 20272-X1178, CCA aid-to-cross #10 Attachment2-Section16_1229 Revised.

Table 41. RPG analysis of ATCO Electric forecasting accuracy in the last 10 years

Additions	2005	2006	2007	2008	2009	2010	2011	2012[3]	2013	2014[2]	10-year average
	($ million)										
Applied-for	48.4	54.0	68.0	43.6	128.5	56.8	68.0	124.6	143.5	140.9	
Approved	48.4	54.0	57.8	37.1	124.5	53.4	86.5	124.6	116.3	114.0	
Actual[1]	31.5	47.0	53.9	59.7	135.0	45.3	85.8	111.9	96.9	90.7	
Variance to applied for	(16.9)	(7.0)	(14.1)	16.1	6.5	(11.5)	17.8	(12.7)	(46.6)	(50.2)	
Variance to approved	(16.9)	(7.0)	(3.9)	22.6	10.5	(8.1)	(0.7)	(12.7)	(19.4)	(23.3)	
% variance to applied for	(34.92)	(12.96)	(20.74)	36.93	5.06	(20.25)	26.18	(10.19)	(32.47)	(35.63)	(9.90)
% variance to approved	(34.92)	(12.96)	(6.75)	60.92	8.43	(15.17)	(0.81)	(10.19)	(16.68)	(20.44)	(4.86)

RPG's accompanying notes: (1) Source is Section 31, Attachment 31.5, Schedule 10-4.
(2) Actual information for 2014 has been updated with information 2014 actuals packages supplied in response to AET-AUC-2015JUN08-003 Attachment 3.
(3) When assembling rebuttal evidence an error was detected in Section 31, Attachment 31.5, Schedule 10-4. This table reflects corrected information for 2012.

1081. The RPG submitted that ATCO Electric had, for the past five years, consistently underspent its requested capital maintenance budget by an average of 32 per cent, which had contributed to over-earning by ATCO Electric in four out of the last five years. In only one of those years (2011) did ATCO Electric's capital maintenance additions exceed approved levels, and only by two per cent. See the following table.[796]

Table 42. Capital maintenance additions - historic variances between actual and approved

Year	Variance
2010	-35%
2011	2%
2012	-57%
2013	-42%
2014	-29%
5-year average	**-32%**

RPG sources: Exhibits 20272-X0003 and 20272-X0284.

1082. The RPG estimated that for the years 2013 and 2014, ATCO Electric over-earned by $6.0 million as a result of over-forecasting its capital maintenance additions by $58.6 million or 36 per cent. This represents a significant cost that customers will not be reimbursed for and for which no true service benefit had been provided. The RPG rebuffed ATCO Electric's rebuttal effort to draw upon a much broader 10-year analysis that included all non-direct assigned capital additions to try and demonstrate their historical forecasting accuracy. The RPG stated that it had removed the capital maintenance only additions from ATCO Electric's 10-year schedule, which demonstrated a minus 20 per cent variance from applied for capital maintenance additions for the

[796] Exhibit 20272-X1297, RPG argument, paragraph 544, page 170.

previous 10 years. The RPG argued that this demonstrated both that the problem has been ongoing for at least 10 years and has grown worse over the last five years.[797]

1083. ATCO Electric challenged the RPG's methodology, arguing that it incorrectly calculated a 10-year average variance for non-direct assigned capital by using dollar variances for all 10 years, which resulted in a higher weighting for higher dollar years. ATCO Electric submitted that "the use of a simple average of the percentage differences (variances of each year) is a more appropriate manner to examine the forecasting accuracy experienced over this time period." ATCO Electric also provided further information[798] as to why the simple average of the variance percentages provides a better reflection of its forecasting accuracy.[799]

1084. ATCO Electric explained that "within the test period, transmission capital maintenance costs are forecast to increase over historical levels due to a variety of factors, including (but not limited to) volume of assets, asset condition, asset performance, failures, safety and environmental requirements, customer requests, as well as regulatory requirements. A failure to deal with these items could compromise the safety and integrity of the system assets." ATCO Electric argued that the recommendations of the RPG to defer or not perform work that was forecast over the test period was not a reasonable approach to executing a capital maintenance program and ought to be rejected.[800]

1085. ATCO Electric argued that the RPG's recommendation to set a ceiling on the total TCM spending budget based on the 10-year historical spending levels corrected only for inflation ($51.6 million) until "measurable degradation of service reliability occurs" should be rejected. It submitted that the RPG appeared to be advocating that ATCO Electric be directed by the Commission to effectively run the system into the ground, to the point of a "measurable degradation" in service before investing in TCM expenditures over the 10-year historical spending levels. ATCO Electric objected to such a direction, as in its view, this would be inconsistent with its statutory obligation under Section 39(1) of the *Electric Utilities Act* to "operate and maintain the transmission facility in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system."[801]

1086. ATCO Electric stated that, based on its experience, many of its assets, including transformers, circuit breakers, switches and substation assets, were approaching the end of their useful life. In order to address the volume of aging assets and associated risks, a more holistic approach, which takes a broader view by leveling the work load and prioritizing the replacement and/or refurbishment of assets already showing deterioration, is the most logical and rational approach. Deferring asset capital maintenance (including replacements and major refurbishments) of this growing inventory of aging assets to future years until "measurable degradation of service reliability occurs" would not reflect responsible program and resource management. The PCB (polychlorinated biphenyl) phase-out program, for example, deals with assets that will require attention within the next 10 years.[802]

1087. The RPG agreed with ATCO Electric that actual circumstances will vary from forecast expenditures. However, it argued that one should expect under-forecasting and over-forecasting

[797] Exhibit 20272-X1297, RPG argument, paragraph 545, page 170.
[798] Exhibit 20272-X1286, AET-RPG-2016APR07-005.
[799] Exhibit 20272-X1298, ATCO Electric argument, paragraph 65, page 28.
[800] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 227-228, page 94.
[801] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 229-230, pages 94-95.
[802] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 234-242, pages 96-99.

to occur to the same degree, on average, such that the average variance in forecasts will diminish over time. The RPG did not consider ATCO Electric's forecasting to meet this expectation and, therefore, to be very strong or reliable. The RPG argued that ATCO Electric has demonstrated persistent over-forecasting.[803]

1088. In reply argument, ATCO Electric submitted that certain recommended approaches were irresponsible and would not lead to the sound operation and maintenance of its transmission system. ATCO Electric pointed out that interveners' use of averages with respect to such things as the vintage of ATCO Electric's asset base, or their reliance on unduly short timeframes provided a distorted representation of the real life situations ATCO Electric must deal with in operating its transmission system. The interveners' use of distorted data suggested that ATCO Electric's forecasting accuracy was far worse than the actual facts confirm. ATCO Electric argued that if the aggregate reductions recommended by interveners were accepted, even in part, by the Commission, it would be impossible for ATCO Electric to operate its system in a prudent manner and in accordance with good operating practices.[804]

1089. ATCO Electric argued that the RPG was inconsistent in relying on the years 2010 to 2014 in asserting that ATCO Electric had historically over-forecast, yet based its cap on a 10-year historical average. Moreover, the RPG selectively focused on just a subset of ATCO Electric's non-direct assigned capital to make its case. ATCO Electric submitted that it had provided variance analyses showing lower expenditure differences, with variances being due primarily to the timing of additions. ATCO Electric acknowledged that it had issues completing TCM work in the recent past due to unusual circumstances including the overall volume of work required and a challenging contractor environment.[805]

Commission findings

1090. The Commission notes that much of the RPG's analysis focuses on the variance between applied-for and actual additions, rather than expenditures. The RPG also analyzed differences between approved and actual additions. These analyses covered the 10-, five- and two-year periods prior to the test years. All showed that ATCO Electric's actual additions were less than forecast. These consistent variances are of concern to the Commission. Significantly, the analyses also demonstrated that more recent years showed an ever poorer record of accuracy in forecasting additions.

1091. While the analysis provided by interveners demonstrating a poor and worsening record of estimating forecast expenditures is concerning, what is of greater concern is the failure of ATCO Electric to demonstrate that it is diligently attempting to improve its forecasting methodology.

1092. ATCO Electric cited its greater work load and contractor issues as factors affecting its operations. These explanations do not allay the Commission's concerns regarding overall forecasting accuracy. The Commission recognizes that ATCO Electric's asset base has grown significantly in recent years and an increased capital maintenance budget should reasonably be expected to follow, albeit with a lag. Also, ATCO Electric's description of its older assets requiring attention is credible. This notwithstanding, the Commission finds it difficult to directly relate the size of the asset base, the timing of additions to rate base, and the age of the assets to the magnitude and timing of expected capital maintenance expenditures.

[803] Exhibit 20272-X1307, RPG reply argument, paragraph 51, pages 18-19.
[804] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 6 pages 4-5.
[805] Exhibit 20272-X1309, ATCO Electric reply argument, paragraphs 159-160, page 59.

1093. Generally, the Commission finds ATCO Electric's forecasting accuracy to be unsatisfactory. Nor does it appear to be improving. However, given ATCO Electric's large base of aging assets and recent additions, it would be unadvisable for the Commission to rely exclusively on a retrospective assessment of forecasting accuracy to set a prospective cap on allowed capital maintenance expenditures. It therefore declines to implement the RPG's recommendation of a cap equal to the 10-year average actual spending rate of $50.9 million per year.

1094. Much of the RPG's analysis focused on capital additions rather than capital expenditures. A balanced perspective requires that the Commission also direct its attention to the latter. The table below displays a comparison between forecast and actual capital maintenance expenditures for the past five years and highlights the average variance between applied for (or forecast) and actual expenditures.

Table 43. Capital maintenance forecast versus actual expenditures

	2010	2011	2012	2013	2014	
	($ million)					
Forecast (1)	54.8	65.4	76.4	96.4	92.0	
Actual	41.8	66.9	56.9	60.3	65.8	
Variance	13.0	-1.5	19.5	36.1	26.2	
% Variance	23.7	-2.3	25.5	37.4	28.5	**5-year average 22.6%**
Sources	(2)	(2)	(3)	(3)	(3)	**2-year average 33.0%**

Note (1): Forecast and actual values are sum of Total Capital Maintenance and Isolated Generation.
Sources: (2) Exhibit 0089.02.AE-650 – forecast values; Exhibit 0003.00.AE-1989 – actual values; (3) Exhibit 0003.00.AE-1989 – forecast values; Exhibit 20272-X1101 – actual values.

1095. This analysis shows that actual expenditures, like actual additions, are well below those applied for, and that accuracy is not improving. ATCO Electric's evidence and argument in this proceeding have not persuaded the Commission that its present forecasts are likely to be more accurate than its past forecasts or, more importantly, that its forecasts, considered in their entirety, are reasonable. The fact that many of ATCO Electric's experienced staff were released or retired in the recent downsizing also does not instill confidence in ATCO Electric's ability to complete all work as forecast, leaving the Commission to conclude that the forecast amounts for capital maintenance are not likely to be fully spent during the test period.

1096. At the same time, however, the Commission accepts ATCO Electric's explanation that the past three years were unusual in terms of capital maintenance additions and are not necessarily determinative of forecasting accuracy, due to a large direct assigned capital project that affected the availability of internal staff who were responsible for supporting both direct assigned and capital maintenance programs.[806]

1097. An additional consideration in evaluating the reasonableness of forecast capital maintenance expenditures and additions is ATCO Electric's service reliability. Many projects are described as being required to provide safe and reliable service to customers. However, ATCO Electric has not sufficiently demonstrated that a decrease in safety or reliability to (anything approaching) unacceptable levels will inevitably result from not completing capital maintenance programs. In particular, the Commission notes that many capital maintenance projects included

[806] Transcript, Volume 6, pages 997-998.

in this application were deferred from previous years but ATCO Electric did not provide evidence to show either deteriorating reliability or a higher probability of such deterioration in the foreseeable future. The Commission understands that these deferrals were the result of various factors, including availability of resources, however, ATCO Electric has not adequately explained why, if a project was previously deferred, it cannot be further deferred. ATCO Electric is expected to prioritize capital maintenance projects to be completed in a test year and adjust its forecast accordingly.

1098. A final consideration in evaluating the forecast capital expenditures and additions for capital maintenance projects, as noted earlier, is the adequacy of business cases. Many of the business cases were less than adequate in providing the detail required and showing a quantitative benefit. The onus is on ATCO Electric to demonstrate that its forecast costs are reasonable. The reasonableness of these forecasts may be supported by the provision of business cases that conform to the Commission's MFR. The Commission finds that, in this instance, the business cases submitted by ATCO Electric do not meet its MFR and, consequently, do not assist the utility in discharging its onus. This, together with the history of over-forecasting and the other considerations mentioned herein, result in the Commission being unable to approve as reasonable ATCO Electric's forecasts as filed.

1099. The Commission considers that it has several options with regard to inadequate business cases: (1) to deny all forecast costs, (2) to approve some portion of the forecast costs, or (3) to direct ATCO Electric to file business cases that meet the MFR in the compliance filing.

1100. For the reasons set out above, the Commission is not persuaded of the reasonableness of the forecast capital maintenance costs and is prepared to approve only a reduced level of expenditures for revenue requirement purposes. The Commission considers that the size of the required reduction is reasonably informed by both the nature of the shortcomings identified in the currently proposed forecasts and observed historical variances from previously approved forecasts. The Commission finds that both the observed two-year average variance from forecast of approximately 33 per cent and five-year average variance of 22.6 per cent are directionally consistent with the application of a 25 per cent reduction to the submitted forecasts. The Commission notes, in this regard, that its selection of a five-year period accords with the period of historical averages used by the Commission to test forecasts. The Commission directs ATCO Electric to apply this 25 per cent reduction to the capital maintenance and isolated generation forecasts (as provided in ATCO Electric's Schedule 10-4) after making adjustments for the Double Circuit project and the relocation projects, the latter being covered by customer contributions. Any adjustments related to directions elsewhere in this decision which affect TCM or isolated generation forecasts (such as the inflation factors addressed in sections 5.2.1 and 5.3) shall be made in the compliance filing in addition to the directed reductions. The Commission directs ATCO Electric to provide the revised TCM breakdown in its compliance filing.

Table 44. Commission-approved capital maintenance expenditures for test period

	2015	2016	2017
	($ million)		
TCM	99.0	124.2	113.0
Isolated generation.*	2.8	2.4	2.2
Total Capital Maintenance	101.8	126.6	115.2
less Double Circuit	3.3	7.3	12.6
less Relocations	17.7	0.8	0.9
Adjusted total	80.8	118.5	101.7
less 25%	20.2	29.6	25.4
Revised total	60.6	88.9	76.3
plus Relocations	17.7	0.8	0.9
Approved Capital Maintenance	**78.3**	**89.7**	**77.2**

References: Exhibit 20272-X1101, Schedule 10.4 and Exhibit 20272-X0130, PDF page 75, 7.0 Project Cost Estimate, Line Relocations.
* Refer to Section 11.4.2.3 Isolated generation projects.

11.4.2.2.1 Double Circuit Mitigation

1101. ATCO Electric explained that Program 50940, Transmission Double Circuit Clearance Mitigation program, is intended to increase the separation between two circuits on the same structure which have potential to create safety hazards or outages by contact or arcing.[807]

1102. According to the RPG, ATCO Electric's Capital Maintenance program relating to double circuit mitigation has thus far incurred an average cost of $2.9 million per line. There are 211 double circuit lines, only 15 of which have been mitigated to date. It was the RPG's opinion that these expenditures were ill-founded and unnecessary.

1103. Given that ATCO Electric has spent $43.4 million on this program between 2004 and 2014 and was proposing to spend another $23 million within the test period, the RPG was concerned that this ongoing program could result in aggregate expenditures of $562 million by the time it is completed.[808]

1104. ATCO Electric stated that this program was required to manage safety and reliability risks due to sagging conductors and argued that the RPG had incorrectly extrapolated the overall cost based on the assumption that all 211 double circuit lines would require mitigation, which was not the case. ATCO Electric stated it "does not intend to mitigate double-circuit lines that do not present safety and reliability risks." As noted in its response to AET-AUC-2015JUN08-031:

> There is no easily forecastable end date to the program itself, as future inter-circuit clearance violations can manifest from the evolution of the province's electric system, be it from load growth, generation growth or system topology changes. This implies that a subset of lines deemed low priority today may become high priority lines in future years as the system evolves. The option of mitigating the clearances on transmission lines and restoring their rating is generally more cost effective than building a new line to alleviate system constraints or other system risks.[809]

[807] Exhibit 20272-X0130, 2 - Capital Maintenance Business Cases - 2015-2017 GTA, PDF page 356.
[808] Exhibit 20272-X1297, RPG argument, paragraph 568, pages 177-178.
[809] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 177, page 66.

Commission findings

1105. In a lengthy exchange conducted at the oral hearing, Commission member Lyttle asked the ATCO Electric panel a series of questions with respect to the double circuit mitigation project.[810]

1106. Commission Member Lyttle referred to the following excerpt from Decision 2013-358 in his discussion with the ATCO Electric panel:

> 471. … Considering that there have been no outages since 2004 due to double-circuit contacts, the Commission considers there to be a reasonable doubt that there will be a risk to the reliability of the system if this program does not proceed as forecast over the test period. Accordingly, the Commission finds that the line survey which is forecast to be completed during the test period nine years after the program started should be completed, ...
>
> 472. With regard to continuation of this project, once ATCO Electric completes a line survey, it is directed to submit detailed business cases in a future GTA escribing the results of the survey and valuating the alternative costs of remediation for any future lines. This evaluation should be done on a line by line basis and include the results of any prioritization assessment with respect to any lines for which remediation is recommended….[811]

1107. The Commission finds that while a business case submitted by ATCO Electric appears to indicate that the line survey discussed in the preceding excerpt was completed, it does not include sufficient detail to support approval of the associated forecast for project completion. For example, the Commission considers that it has not been provided with enough information to allow it to assess the reasonableness of work prioritizations based on individual line evaluations. Consequently, the Commission considers this information to be insufficient to support ATCO Electric's request for approval of this project.

1108. ATCO Electric witnesses confirmed that the utility had received a letter from the AESO, dated October 6, 2014, which confirmed that the 144-kV transmission lines clearance mitigation plan was "consistent with those used or to be used by the AESO in its planning studies, based on current information."[812] The Commission considers that both the date and content of this correspondence is significant in its assessment of the reasonableness of ATCO Electric's current project forecasts. The October 2014 AESO correspondence was received well in advance of the revision of the AESO's Long-Term Transmission Plan in November of 2015, which confirmed that a significant number of direct assigned capital projects were no longer expected to proceed in accordance with the previously projected timelines. This letter also nowhere states that the AESO had assessed the sufficiency of ATCO Electric's change mitigation plans at that point in time. The Commission finds ATCO Electric's reliance on the content of this letter to support the reasonableness of its current forecasts to be unjustified in the absence of additional analyses or supporting facts as detailed in Direction 42 of Decision 2013-358. In any event, it cannot reasonably provide the required foundation for the Commission's approval of costs of this magnitude.

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[810] Transcript, Volume 10, pages 1665-1676.
[811] Decision 2013-358, paragraphs 471 and 472.
[812] Exhibit 20272-X0130, 2 - Capital Maintenance Business Cases - 2015-2017 GTA, PDF page 369.

1109. The Commission does not find it reasonable to assume that, as suggested by the RPG, the double circuit mitigation project will result in a future expenditure of over a half billion dollars. However, it finds that work of this kind should be undertaken in a way that controls costs to the extent possible.[813]

1110. The Commission is concerned by the lack of support for the double circuit project in the utility's application. In ATCO Electric's last GTA (Proceeding 1989), the Commission set out the requirements for a business case that would be sufficient to support the project. Specifically, the Commission stated that ATCO Electric was to submit a business case "describing the results of the survey and evaluating the alternative costs of remediation for any future lines. This evaluation should be done on a line by line basis and include the results of any prioritization assessment with respect to any lines for which remediation is recommended." The business case provided by ATCO Electric does not comply with this direction.

1111. Furthermore, the AESO letter which ATCO Electric has submitted to support the project does not provide details of any discussions between these parties. It is not clear to the Commission what part or parts of the business case the AESO is specifically supporting.

1112. Given the lack of business case support provided by the utility in its application, the Commission is not prepared to approve any of the expenditures forecast for the double circuit project in the test period and directs ATCO Electric to remove the expenditures from its current forecast. ATCO Electric is directed to submit a business case with the requested level of detail in its next GTA.

11.4.2.2.2 Keg River Substation Rebuild

1113. The RPG noted that ATCO Electric's proposed rebuild of the Keg River 789S substation was the second largest project in the 50060 capital maintenance program "Substation Rebuilds," and was estimated to cost $11 million. The RPG argued that the expense could be avoided by salvaging the substation instead of rebuilding it, and that this was an appropriate course of action because "the Keg River station no longer plays any significant role in the overall operation of the system." The RPG cited Section 2(a) of the *Hydro and Electric Energy Act* in support of its position and made the following recommendation:

> 588. The Ratepayer Group recommends that the Commission direct AET to halt all spending on this project, initiate a review of Decision 21300-D01-2016,[814] and direct AET to obtain from the AESO and submit to the Commission review process a written direction to proceed with the replacement of Keg River 789S supported by AESO analysis and documentation that demonstrates that this project is required to meet the needs of Alberta and is in the public interest. (footnote omitted)[815]

1114. ATCO Electric submitted that the proposed rebuild of the Keg River Substation was approved in Decision 21300-D01-2016 and that the RPG was asking the Commission to initiate a review of that decision in this proceeding. The RPG requested the Commission to direct ATCO Electric to obtain "a written direction to proceed ... supported by AESO analysis and documentation" from the AESO which, it submits, should then be subject to a Commission

[813] Transcript, Volume 10, page 1677, lines 10-13.
[814] Decision 21300-D01-2016: ATCO Electric Ltd., Keg River 789S Substation Rebuild, Proceeding 21300, Applications 21300-A001 to 21300-A005, March 29, 2016.
[815] Exhibit 20272-X1297, RPG argument, paragraphs 587-588, pages 182-183.

review process. ATCO Electric argued that the "RPG was asking this Commission to take on the role of system-planner and override the AESO's determination that the Keg River substation is still required as part of the AESO's long term planning."[816]

1115. In rebuttal evidence, ATCO Electric explained there would be an operational impact[817] if the Keg River substation was salvaged as a number of lines would have to be joined. ATCO Electric explained further:

> The long transmission lines that would have to be conjoined if Keg River was removed, raise operational concerns as equipment voltage limits would be exceeded when these long lines are energized. In order to mitigate this, at a minimum a line reactor would be required at one end of the line.
>
> Salvaging 789S Keg River substation would also have an adverse effect on the voltage stability of the Rainbow Area as the voltage stability margin would be reduced.[818]

1116. ATCO Electric also pointed out that there would be performance impact issues, stating:

> From a line availability perspective, the long lines that would be formed assuming the removal of Keg River, would have a higher probability of being out of service, which will have a consequence on system reliability. The reliability of these lines becomes more important in future if these lines are tapped to serve area development.
>
> The average length of AET 144 kV lines is 49 km and 75% of the population is 83 km or less. These conjoined lines will be at the extreme end of line lengths in the ATCO territory. The new line formed by conjoining 7L62 (82km) and 7L64 (143km) will have a total length of over 225 km, and the new line formed by conjoining 7L58 (82km) and 7L59 (92km) will have a total length of over 174 km. The increased exposure will result in lower reliability to the Rainbow Lake and High Level areas.
>
> Also, there are challenges protecting these long lines. Protection relays would be unable to detect a line to ground fault on the remote end of the conjoined 7L62 and 7L64 line, given the infeed contributions from tapped substations. This presents a safety concern.[819]

1117. ATCO Electric also noted that the long-term need had been vetted with AESO throughout the project's evolution and that the AESO had confirmed the need in a letter.[820]

Commission findings

1118. The Commission is satisfied with ATCO Electric's explanation of the role of the Keg River substation in providing electrical service to the designated area. It is also persuaded that the utility's rationale for proceeding with the rebuild is reasonable. Given the AESO's confirmation of the long-term need, the cost of the project is hereby approved.

1119. The Commission rejects the RPG's recommendation to initiate a review of Decision 21300-D01-2016, within the context of this proceeding.

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816 Exhibit 20272-X1309, ATCO Electric reply argument, paragraphs 185-188, page 70.
817 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 127.
818 Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 127.
819 Exhibit 20272-X1120, ATCO Electric rebuttal, PDF pages 127-128.
820 Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 262.

11.4.2.3 Isolated generation projects

1120. Isolated generation consists of generation plants that are required to supply electricity for remote communities, industrial sites and ATCO Electric telecommunication sites that are not connected to the electrical grid. Isolated generation often constitutes the sole source of power in these instances. Isolated generation plant assets include engines and turbines, as well as protection and control equipment, and buildings.[821]

1121. ATCO Electric forecast small capital expenditures and capital additions for work on the isolated generation projects. ATCO Electric monitors the condition of its isolated generation facilities and has identified capital maintenance projects required to ensure that these facilities continue to operate in a safe, reliable and environmentally responsible manner. The forecast for isolated generation projects is as follows:

Table 45. Isolated generation: forecast capital expenditures and additions for test period

	2015 forecast		2016 forecast		2017 forecast	
	Expenditure	Addition	Expenditure	Addition	Expenditure	Addition
Project and description	($ million)					
90067: Rebuild Jasper Palisades Substation	0.0	0.3	-	-	-	-
90130: Refurbish/Replace Engines and Turbines	1.4	2.7	3.1	3.1	3.0	3.0
90140: Transmission Isolated Operations Capital Maintenance	1.4	1.5	1.0	1.0	0.9	0.9
Unspecified			(0.1)		(0.1)	
Total	**2.8**	**4.5**	**4.1**	**4.2**	**3.8**	**3.9**

Source: Exhibit 20272-X1101, attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4.
Note: Numbers may not add up due to rounding.

1122. ATCO Electric provided business cases for projects 90130 and 90140.

1123. For comparison, actual capital expenditures for Project 90130 were $5.4 million, $4.9 million and $2.3 million for 2012, 2013 and 2014, respectively. In the business case for Project 90130,[822] ATCO Electric identified six life extending activities and three unit replacements for 2015, three life extending activities and two unit replacements for 2016, and four life extending activities and one unit replacement for 2017.

1124. In the application,[823] ATCO Electric confirmed that Project 90067, involving the replacement of major components at the 781S Palisades substation that have reached end of life, were forecast to cost $1.9 million with an in-service-date of December 31, 2012 as part of its 2011/2012 GTA filings, but was subsequently put on hold with relatively minimal expenditure to permit an opportunity to evaluate the overall transmission strategy for Jasper. A second major project, Fort Chipewyan capacity increase (Project 90134), was removed from the forecast during the October 2015 update. During the update, ATCO Electric also made an unspecified reduction to capital expenditures.

821 Exhibit 20272-X0002, PDF page 528.
822 Exhibit 20272-X0130, 2 - Capital Maintenance Business Cases - 2015-2017 GTA, PDF pages 451-458.
823 Exhibit 20272-X1099, revised application narrative – blackline, PDF page 198

1125. ATCO Electric stated that the average forecast expenditures for isolated generation for the three-year test period are lower than the actuals for the previous three years.[824]

1126. No issues were raised by any of the interveners in evidence, argument or reply argument with respect to the proposed isolated generation projects.

Commission findings

1127. The Commission finds that the forecast capital expenditure increases for Project 90130 in 2016 and 2017 to refurbish/replace engines and turbines are not justified. They represent increases of more than 100 per cent over 2015 levels. The submitted business case confirmed that fewer life-extending activities and replacements would be occurring in 2016 and 2017 than in 2015. The Commission accepts that the number of activities alone is not a sufficient indicator of the reasonableness of the overall forecast, however, in this case, the work proposed for completion in each of 2015 and 2017 is very similar. For example, three of the life extension projects are identical in terms of location, unit type, and proposed work. Similarly, the proposed customer-funded life extensions are both overhauls of natural gas units at the same location, with work on a larger unit forecast to occur in 2017. Other work identified in the business plan includes a 2015 forecast for a major overhaul on a 1,000 kilowatt (kW) unit and replacement of a 25-kW unit, a 50-kW unit and a mobile unit, while the 2017 forecast is for the replacement of a single 140-kW unit. The Commission is not persuaded that this difference alone justifies the observed increase in forecast capital expenditures from $1.4 million to $3.0 million. ATCO Electric is directed to revise the Project 90130 forecast costs for 2016 and 2017 to 2015 levels.

1128. The Commission finds the total forecast costs for the isolated generation projects, other than Project 90130, to be reasonable. The forecast amounts for 2015, 2016 and 2017 for these projects as set out in Table 45, are approved, subject to the adjustments that are required to these projects to reflect the directions of the Commission elsewhere in this decision.

11.4.3 Asset management

1129. ATCO Electric stated that it "undertook a gap analysis of processes and practices against ISO 55001, which is the international standard that identifies common 'good practice' that applies to asset related industries. AET has revamped existing and developed new standards, processes and practices into an ISO 55001 compliant Asset Management System (AMS) and is in the process of implementing this system. An Asset Management Office (AMO) has been established to take responsibility for the overall governance and direction of AET's AM system."[825] Asset management is a topic that has been addressed in previous ATCO Electric GTAs.

1130. Calgary argued that a full, comprehensive and proper business case for asset management was needed, and that the costs of ATCO Electric's proposed asset management activities for the test years should be disallowed until one could be provided. Calgary also submitted that ATCO Electric should be directed to seek, and obtain, ISO certification for its asset management program before any program related expenditures are included in rates.[826]

[824] Exhibit 20272-X1099, revised application narrative – blackline, PDF page 159
[825] Exhibit 20272-X1100, revised application – clean, paragraph 124, PDF page 69.
[826] Exhibit 20272-X1299, Calgary redacted argument, paragraph 22, page 8.

1131. Calgary submitted that for the asset management program, it appeared that ATCO Electric had filed a "hodge podge" of business cases, none of which met the required criterion for regulatory filing purposes.[827] Calgary stated that the ATCO Electric witness appeared to confirm that two separate business cases[828] were completed, one for each of the implementation, and post-development phases of asset management.[829] During examination by Commission Member Lyttle at the oral hearing, the ATCO Electric witness confirmed that the asset management program was more than an "IT system:"

> You're developing your asset management systems to that ISO 55001 standard; is that correct?
> A. MS. CLARK: We're developing them in alignment --
> Q. In alignment.
> A. MS. CLARK: -- with the standard. And to be clear, it's not an IT system. We have IT systems, Oracle and Maximo, we're using them, but the system itself -- and we just went through some of the documents that were produced as part of the system --
> Q. Right.
> A. MS. CLARK: -- so that we can get consistent approaches to how we deal with asset-related decisions.[830]

1132. The witness went on to discuss the business case filed in ATCO Electric's previous GTA as follows:

> Q. And that was probably -- and that's why I was looking at the AESO [sic], because in '13-'14, if my memory serves me, from that exhibit we brought up yesterday, we actually had an AESO -- sorry, we had an ISO 55001 business case; correct?
> **A. MS. CLARK: We did include a business case and it is on the record in that City of Calgary response I think we were looking at yesterday. It was an IT-ish nature, and it was based on our early thinking about what asset management was and how we would go about it. We did not proceed with that scope. The scope that we actually proceeded with was in alignment with the system development business cases, Phase 1 and 2.**[831] [emphasis added by Calgary]

1133. Calgary submitted that for a program such as asset management, which involved significant expenditures and the likelihood for additional expenditures beyond the test period, a business case should reflect a valid understanding of the program being considered and the requirements for implementation, as well as a full cost/benefit analysis based upon the life cycle costs of the program or project.[832]

1134. Calgary stated that the level of expenditures which ATCO Electric was forecasting for its asset management program was substantial. The requested capital for opening rate base was $4.0 million, while forecast capital and operating costs for the three test years would add another

827 Exhibit 20272-X1299, Calgary redacted argument, paragraph 50, page 16.
828 The two business cases were filed as follows: (1). Exhibit 20272-X0131, PDF page 147 of 182, Project No. 81057, Transmission Asset Management System (TAMS) Phase 2 – Implementation and (2) and Exhibit 20272-X0640, AETCAL-2015OCT16-10(h), Attachment 1, Project No. 81066, Transmission Asset Management Program.
829 Transcript, Volume 1, page 61, line 2 to page 63, line 8.
830 Transcript, Volume 10, pages 1654-1655.
831 Transcript, Volume 10, page 1655.
832 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 50-53, pages 16-17.

$6.0 million in costs. Calgary summarized its understanding of ATCO Electric's asset management program costs in the following table.[833]

Table 46. Asset Management program costs

Asset Management program	20272-X1101	2014	2015	2016	2017	2015-2017
Cost in $000,000	Schedule	Additions	Forecast	Forecast	Forecast	Forecast
Capital projects(1)						
Direct General PP&E						
Phase 1-Development	S 10-4	1.5				0.0
Phase 2-Implementation	S 10-4	2.5	1.2			1.2
IT Projects	S 10-9		0.1	0.8	1.8	2.7
Capital projects totals		**4.0**	**1.3**	**0.8**	**1.8**	**3.9**
Operating costs(2)						
Phase 2-Implementation	S 5-1, Acct 566	0.0	0.4	0.8	0.9	2.1
Asset Management Office (AMO) FTEs(3)						
Capital		10.3	4.8	2.0	2.1	
O&M		0.0	2.2	4.6	4.9	
Totals		**10.3**	**7.0**	**6.6**	**7.0**	

Sources:
(1) Exhibit 20272-X0640, AET-CAL-2015OCT16-010(i) Attachment.
(2) Exhibit 20272-X0640, AET-CAL-2015OCT16-010(i) Attachment.
(3) Exhibit 20272-X0640, AET-CAL-2015OCT16-009(e).

1135. Calgary submitted that taken together, "ATCO Electric will have spent close to $10 million on work which is directly involved with, or related to, asset management, without any full and complete business case being filed to date, and without ATCO Electric achieving certification that it is compliant with ISO 55001." Calgary noted that ATCO Electric had stated it was not planning to seek certification that its asset management program was ISO compliant.[834]

1136. According to Calgary, ATCO Electric confirmed in testimony during the oral hearing that it had altered its business case to implement the asset management program and that the business case submitted to the Commission for approval in the 2013-14 GTA was not carried out, and instead a different project was completed:

> Q. …help me understand the difference between the two.
> A. MS. CLARK: Certainly. So the business case -- and let me just make sure I've got the right one. The business case attached as 10(e) was filed in our 2013-'14 general tariff application, and it contemplated an asset management system, and it -- the thinking at that time was that we would be pursuing some IT fixes, and I think that was -- you know, we were in probably late 2011, 2012 at that time when we were preparing that application. So that would be what I would characterize as some early thinking around what we anticipated we would be doing in the 2013-'14 time period.
> **We did not proceed with the work as characterized -- the work scope as outlined in that business case. What we did proceed with was the scope of work as outlined in**

[833] Exhibit 20272-X1299, Calgary redacted argument, paragraph 73, page 22.
[834] Exhibit 20272-X1299, Calgary redacted argument, paragraphs 74-75, pages 22-23.

> **the business case attached at CAL-10(h), which is dated July 12th, 2013.**[835] [emphasis added by Calgary]

1137. Calgary submitted that the "Phase II," or implementation portion, of the business case set out in AET-CAL-2015OCT16-10(h) Attachment 1 did not provide specific information or evidence to demonstrate exactly how ATCO Electric would go about implementing the asset management program.[836]

1138. Calgary further submitted that ATCO Electric's responses to a series of questions from Commission Member Lyttle at the oral hearing confirmed that there was no single, comprehensive business case in this proceeding for implementing asset management. Also, there was no way to isolate the operating costs of the program in the applied for revenue requirement.[837]

> Q. Right. I guess where I was looking at, because I was on the '13, '14, and we approved that business case. But now I was expecting to see something else on [ISO], and I don't have anything. It's almost smattered among all business cases now. Is that correct?
> A. MS. CLARK: There are elements of it that are in evidence, I think, in our transmission capital maintenance business cases. Because of the increase in our capital maintenance workload associated with the age and condition of some of our assets, we really focused, in terms of implementation efforts, there first. We are turning our attention now to some of our operations and maintenance practices and viewing them through a similar sort of risk, cost, and performance lens.
> Q. Is there any way that we can isolate those 55001 costs or no in the current application? What they are by business case or in total?
> A. MS. CLARK: So I think we've got explicit business cases for the development of the system and the implementation of the system. Once the system is in place and people are using it and following the processes and practices, it would become part of our normal mode of operation, and those costs would be, you know, not significantly different, I don't think, from what the costs previously would have been to develop a particular business case. It's just that they're doing so to a consistent -- using a consistent approach.[838]

1139. Calgary noted that ATCO Electric had confirmed in testimony[839] that the asset management program was substantially implemented by the middle of 2015.

1140. Calgary argued that, even though ATCO Electric claimed it was developing a standard in alignment with ISO 55001, there was no objective and reliable basis for the Commission to determine whether ATCO Electric had achieved what it set out to do for the development and implementation of the asset management program. In its view, this would not be possible without certification, a step ATCO Electric was not planning to take.

1141. Calgary submitted that certification was necessary and should be obtained, at ATCO Electric's cost, prior to any further asset management expenditures being included in rates.[840]

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835 Transcript, Volume 1, page 57.
836 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 79-80, pages 24-25.
837 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 83-84, pages 26-27.
838 Transcript, Volume 10, pages 1656-1657.
839 Transcript, Volume 1, page 59, lines 19-20 to page 60, lines 8-15.
840 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 95-96, page 30.

1142. Calgary further argued that if ATCO Electric had filed a proper and complete business case for asset management, the Commission and other parties would be better able to understand and assess the impact on asset values arising from ATCO Electric's proposed program. Without such support there was no basis to assess the program. Calgary again noted that the Commission required both life cycle operating costs as well as a cost/benefit analysis to be included in business cases for proposed capital projects, but that neither the business case relied upon by ATCO Electric to develop and implement asset management,[841] nor the one previously approved by the Commission for the program[842] contained these elements. In the result, it must be concluded that ATCO Electric has failed to meet its statutory onus with respect to the requested expenditures.[843]

1143. Calgary submitted that:

> 106. The Commission should disallow all capital ($4.0 million requested for 2014 opening rate base, and the additional $3.9 million requested in the 2015-2017 test years) until AET has filed a Business Case that meets previous Commission directives including a detailed cost/benefit analysis, a benefits realization plan and an ISO 55001 certification report.
>
> 107. The Commission should direct the Asset Management Office (AMO) O&M headcount for 2016 and 2017 be reduced to the 2015 level of 2.2 FTE. This will reduce the AMO O&M spend for the 2015-2017 test years by approximately $5.1 million.[844] [845]

1144. Calgary noted that ATCO Electric's witness, Ms. Clark, confirmed she was not aware of the ISO guidelines or criterion for realizing value for assets using as asset management approach. In Calgary's view, this suggested that ATCO Electric's "assertive claims" in argument were "hollow and unsupported." Calgary took the position that the utility could not validly claim that it was in the post development, implementation phase of its program, with "fairly minor" steps to be completed, when there was no evidence of what steps ATCO Electric was taking to implement the program.[846]

1145. The RPG recommended that the Commission reject ATCO Electric's request for an additional 4.9 FTEs in an asset management office to oversee asset management activities for the following reasons. First, the $2.9 million in expenditures ATCO Electric has requested for Project 82660 – Asset Information Management System, include software costs and internal and external labour costs for the development of the new systems. And second, the new systems are intended to improve staff efficiencies. According to the RPG, since the FTEs in the test period had already been budgeted for in the capital costs of the development program with the expectation of achieving efficiency improvements, the latter should offset the requirement for the 4.9 FTEs in the long term.[847]

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841 Exhibit 20272-X0640, AET-CAL-2015OCT16-10 (h), Attachment 1 Project 81066 – Transmission Asset Management Program.
842 Exhibit 20272-X0640, AET-CAL-2015OCT16-10 (e), Attachment 1 Project 82407 –Asset Management System.
843 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 101-104, page 32.
844 Exhibit 20272-X1299, Calgary redacted argument, paragraphs 106-107, page 33.
845 Exhibit 20272-X1299, Calgary redacted argument, paragraph 151, page 47, Table 6-Recommended O&M Reductions, Reduced AMO (Asset Management Office) FTEs.
846 Exhibit 20272-X1308, Calgary reply argument, paragraphs 37-38, page 10.
847 Exhibit 20272-X1307 RPG reply argument, paragraphs 165-166, page 49.

1146. ATCO Electric submitted it had established its AMO to assume responsibility for the overall governance and direction of its asset management system, which was to be used to address decision making and practices in a manner that complies with ISO 55001. It explained that the development of a new asset management system was a direct response to the growth of its asset base in the last number of years; the decrease in the level of experience of its workforce, the vast majority of which had less than 10 years' experience with ATCO Electric; as well as the volume of assets in ATCO Electric's fleet approaching end of life. ATCO Electric stated that "… the asset management system balances costs, risks and performance in developing a proper and consistent approach to managing AET's assets."[848]

1147. ATCO Electric stated that its asset management system was substantially complete.[849] It submitted that the outstanding component related to competencies to be fully compliant with the ISO standard and that these were fairly minor and were all that remained to be completed. ATCO Electric asserted that although its asset management system was in alignment with the ISO 55001 standard, it did not plan on seeking formal certification, as this was a time consuming and costly exercise. According to the utility, it had achieved the benefits of compliance with this standard without incurring the costs of certification.[850]

1148. ATCO Electric submitted that the establishment of an AMS would ensure that it has improved and consistent standards and processes that will lead to better and more consistent management of its fleet of assets on a go-forward basis. The benefits of implementing the asset management system could not be evaluated solely by looking at program costs and then asking for a companion quantification of benefits for the AMS program itself, considered in isolation. The benefits are derived from the application of improved processes that are consistent with an internationally recognized standard — ISO 55001, and which will lead to benefits regarding decisions for ATCO Electric's entire fleet of assets.

1149. ATCO Electric stressed that the AMS balances costs, risks and performance in developing a proper and consistent approach to managing ATCO Electric's assets. "As such, this is not a one-off benefit analysis that can be precisely quantified prior to the actual implementation of the program. Instead, the AMS will lead to the development of good internal practices for managing assets that will drive sound decision making in the future."[851]

1150. ATCO Electric submitted that it had provided full justification for the implementation of this program and had demonstrated that it was necessary to ensure that ATCO Electric had sound decision making practices and processes in place for the management of its entire fleet of assets.

1151. ATCO Electric noted that its updated application[852] detailed its growing asset base, the increasing number of its assets approaching end of life, as well as the impacts of increasing regulatory requirements and an aging workforce. ATCO Electric stated that its asset base was in excess of $5 billion and required a strong asset management system to effectively manage it. The utility confirmed that it had conducted a "gap analysis" using the then existing international standard (PAS 55).[853] As set out in its business case,[854] ATCO Electric intended to address the

[848] Exhibit 20272-X1298, ATCO Electric argument, paragraphs 74-75, pages 31-32.
[849] Exhibit 20272-X0640, AET-CAL-201500T16-10(h).
[850] Exhibit 20272-X1298, ATCO Electric argument, paragraph 76, page 32.
[851] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 70, page 29.
[852] Exhibit 20272-X1100, revised application – clean, Section 5, pages 5-7 to 5-10.
[853] Exhibit 20272-X0301, pages 45-47.
[854] Exhibit 20272-X0640, page 89.

identified gaps by developing an ISO 55001-compliant asset management system. It claimed that the benefits of its asset management system were clearly demonstrated by the evidence on the record.[855]

1152. In a table summarizing projects in excess of $500,000, ATCO Electric provided the following summary of the asset information management system (Project 82660):

> **Software Purpose**
> The Asset Information Management program will leverage information such as asset data (age, maintenance schedules, drawings, etc.), maintenance procedures, engineering drawings, and GIS data to provide improved business intelligence and data access for maintenance planning and the field workforce.
>
> **Business Rationale**
> ATCO Electric currently has asset information segregated in separate data bases: MAXIMO, CROW, Oracle, MOPS and GIS information systems. To implement an asset management information solution, this Project seeks to establish an integrated asset information strategy to ensure asset information is available to support effective and timely business decision making.
>
> **Alternatives Considered**
> ATCO Electric considered five alternatives, ranging from the status quo to implementing a one enterprise solution that integrates all asset management functionality on one platform.
> ATCO Electric will implement the Project in two phases. The first phase will be an exploration phase to determine the most appropriate and cost-effective solutions. The second phase will be the implementation of the solutions, as planned.
>
> **Protect Benefits**
> The business case outlines examples of costs savings associated with asset management decisions that can be informed by an integrated asset information management system. The benefits of a structure asset management information system are listed in Exhibit 20272-X0131 at page 102, and include: asset life optimization and increased prediction of critical capital maintenance through enhanced decision-making; creating a single source of data and consolidated record, which will enhance data accuracy; identification in opportunities for work scheduling; and more accurate planning and budgeting.[856]

Commission findings

1153. The Commission is satisfied that asset management is a worthwhile endeavor and ATCO Electric's efforts will ultimately provide a benefit to the utility and its customers. However, the Commission is of the view that Calgary has identified legitimate concerns with ATCO Electric's past, current and planned future expenditures on its asset management program. It appears that the execution of the asset management project is, and has consistently been, much more involved and expensive than indicated by any of the business cases that have been provided by ATCO Electric.

1154. The business case for Project 82660 shows that a number of IT systems (MAXIMO, CROW, Oracle, MOPS and GIS information systems) contribute to the working of an asset management system. However, the Commission has never been provided with a business case

[855] Exhibit 20272-X1309, ATCO Electric reply argument, paragraphs 72-73, pages 29-30.
[856] Exhibit 20272-X1309, ATCO Electric reply argument, paragraph 207, page 85.

for asset management that includes all the components that appear to be necessary for it to function and provide ATCO Electric with its desired benefit. For example, the following table reflects many, but not all, of the components that appear in the schedules and business cases from 2012 to 2017.

Table 47. Asset Management projects and components

Project	2012	2013	2014	2015	2016	2017	Total
	($ million)						
81066 Transmission Asset Management program	0	1.2	2.8	1.2			5.2
82407 Asset Management(1)	0.1	0.5	0.5				1.1
82416 Maximo Enhancements	0.1						0.1
82417 Maximo/Oracle Integration(2)	0.2	0.1	0.1				0.4
82431 Maximo Upgrade	0.2	0.1					0.3
82437 Equinox CROW Phase II	0.2						0.2
82477 Oracle Upgrade		0.3					0.3
82660 Asset Information Management System				0.7	0.9	1.7	3.3
Facilities & Asset Management(3)			3.1	1.5	2.9	1.9	9.4

Sources:
(1) Proceeding 1989 (amounts shown are 50 per cent; distribution assigned an equal amount.
(2) Proceeding 1989.
(3) Exhibit 20272-X0004, Schedule 10-4, lines 461 and 642.

1155. The information in the above table presents a confusing picture of the asset management project. For example, some IT programs which ATCO Electric has stated are integral to asset management appear as separate projects even in the same years, while others do not appear to be carried forward. The Commission finds there is insufficient well-organized evidence to demonstrate that the project is or will be functional. Also of concern to the Commission is the fact that the business case for Project 82660 has not identified a preferred alternative solution nor does the business case appear to be approved internally.

1156. Given ATCO Electric's description of asset management in the business case for project 82660 and how it should integrate with MAXIMO, CROW, Oracle, MOPS and GIS information systems, the Commission is of the view that a comprehensive business case treating all these components as a single project is required. This business case should itemize all the work required, including any necessary enhancements or upgrades to the various IT systems on an historical and go-forward basis. This business case should also provide a cost/benefit analysis with a clear description of future cost requirements including as much of the life cycle as can reasonably be anticipated. ATCO Electric is directed to provide such a business case in its next GTA.

1157. The Commission will not reconsider the Asset Management program-related costs for inclusion in ATCO Electric's revenue requirement until the directed supplemental business case is provided for evaluation in the next GTA.

1158. For purposes of determining the opening rate base in 2015, 2014 additions totalling $4.0 million related to asset management are disallowed. Forecast expenditures in all test years related to asset management totaling $3.9 million are also to be removed in addition to related O&M expenses totaling $2.1 million. ATCO Electric is directed to make these adjustments in its compliance filing.

11.4.4 Transmission software costs

1159. ATCO Electric provided the following forecast for capital spending associated with software projects:

Table 48. Software projects: forecast capital expenditures and additions for test period

	2015 forecast		2016 forecast		2017 forecast	
	Expenditure	Addition	Expenditure	Addition	Expenditure	Addition
Project and description	($ million)					
Enterprise IT	1.4	1.5	1.6	1.6	1.6	1.6
Facilities & Asset Management	1.5	1.6	2.9	2.9	1.9	1.9
IT Infrastructure & Foundational Initiatives	1.6	2.0	2.9	2.9	1.0	1.0
Project & Financial Management	2.1	2.2	1.9	1.9	1.3	1.3
Revenue and Regulatory Management	0.1	0.1	-	-	-	-
Total	**6.7**	**7.3**	**9.3**	**9.3**	**5.7**	**5.7**

Source: Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, schedule 10-4.
Note: Numbers may not add up due to rounding.

1160. These project categories contain 34 distinct IT projects. ATCO Electric submitted business cases for 21 projects, of which 17 included forecast costs for the test years.

1161. Project 82690, described as "Silvacom data and application repatriation," is the only project with cumulative forecast costs over $500,000 during the 2015-2017 test period that does not have a business case associated with it. When the application was initially filed, the forecast cost for Project 82690 was $0.4 million, which ATCO Electric claimed[857] put it under the $500,000 threshold for requiring a business case. The updated application forecast Project 82690 to cost $0.8 million over the 2015-2017 test period.

1162. Approximately $15.7 million of the forecast $22.3 million in software project capital additions over the 2015-2017 test period required business cases because the individual projects involved were each forecast to cost over $500,000. Calgary argued that the submitted business cases do not include minimum filing requirement information established in Decision 2013-358, including incremental 10-year capital and operating costs of alternatives, discount or investment rate, or the annual costs of alternatives for the period analyzed. Calgary argued that none of the business cases met Commission requirements and that, consequently, inclusion of the $15.7 million amount in revenue requirement should be disallowed.

1163. The RPG was generally supportive of Calgary's argument regarding software projects and shared concerns about the lack of support in business cases, including the lack of cost/benefit analysis.

1164. ATCO Electric stated that it identified alternatives where reasonable alternatives existed and considered the most appropriate and economic option to meet identified needs.[858] ATCO Electric argued that its business cases were "adequate, clearly establish the need for the projects, and establish a reasonable forecast of the capital cost of these projects."[859]

[857] Exhibit 20272-X1166, AET Undertaking 2 - Jansen to Evanchuk, Modifications to Calgary Aid Exhibit #3 - ATCO Electric Transmission - 2015-2017 GTA Business Cases.
[858] Exhibit 20272-X1298, ATCO Electric argument, PDF page 125, paragraph 308.
[859] Exhibit 20272-X1309, ATCO Electric reply argument, PDF page 76, paragraph 203.

1165. The utility explained that the "software" category of assets was determined on an allocation basis between ATCO Electric transmission and distribution in the previous GTA. ATCO Electric confirmed in its IRs[860] that no "allocated" asset categories would remain after the reorganization.

1166. For comparison, ATCO Electric's software expenditures were $8.1 million, $13.9 million and $8.2 million in 2012, 2013 and 2014, respectively. ATCO Electric's software capital additions were $7.6 million, $15.8 million and $8.9 million in 2012, 2013 and 2014, respectively.

Commission findings

1167. The Commission finds that when ATCO Electric updated the application and costs for Project 82690 it also should have submitted a business case because the forecast costs for this project increased to more than $500,000. There is no basis to justify, in the public interest, the forecast for the project when the available information, namely a cost and project title, is insufficient to determine what the project is or why it is needed. Prior to arriving at its determination with respect to this project, the Commission considered the following four options: (1) deny all costs, (2) approve only the original cost forecast of $0.4 million, (3) approve up to the business case requirement threshold of $499,999, or (4) direct ATCO Electric to file a business case in the compliance filing. The Commission finds that the creation of a business case is a basic, uncomplicated function, and one that should have been undertaken for Project 82690 when the cost forecast doubled, if only as part of an exercise to consider why the costs doubled and to assess whether the project is still feasible and needed at the new cost level. Costs for Project 82690 are denied. ATCO Electric is directed to remove this project cost in the compliance filing.

1168. The Commission's general views with respect to ATCO Electric's submitted business cases are discussed in Section 11.1.5. The business case for projects 82582, 82585 and 82689, Enterprise Technology Infrastructure Enhancements, was found particularly lacking given that it was forecast to be one of the larger IT capital projects with costs forecast at $2.5 million for the 2015-2017 test period. The forecast costs for this business case account for approximately 15 per cent of the software project spending over the test period. The shortcomings of the business case are reflected in the vague description of potential benefits, a single alternative considered (which was to do nothing), and a forecast methodology and assumption section containing the solitary statement that "[t]he OCIO and IT service provider collaborated to produce the estimates for these initiatives." The forecast methods and assumptions description is the weakest of the submitted software business cases. The business case does not sufficiently address why the status quo is not a viable alternative when the identified mitigations for key risks of not implementing the projects appeared to suggest that acceptable mitigations were available. The Commission finds that the overall deficiencies in this business case result in insufficient evidence to support the project. Forecast costs for projects 82582, 82585, and 82689 are denied. ATCO Electric is directed to remove these project costs in the compliance filing.

1169. Software associated with the asset management program is discussed in Section 11.4.3.

[860] Exhibit 20272-X0281, AET-AUC-2015JUN08-101, PDF page 214.

1170. The Commission finds the remaining forecast costs for software projects to be reasonable. They are approved for inclusion in revenue requirement, subject to adjustments that are required to reflect the directions made by the Commission elsewhere in this decision.

11.4.5 Direct general PP&E

1171. Direct general PP&E capital projects are intended to ensure that the tools, equipment and furnishings necessary for ATCO Electric personnel to perform their work are available. The projects also provide for routine capital maintenance on existing buildings and infrastructure. The allocated share of direct general PP&E capital project forecast is as follows:

Table 49. Direct general PP&E: forecast capital expenditures and additions for test period

	2015 forecast		2016 forecast		2017 forecast	
	Expenditure	Addition	Expenditure	Addition	Expenditure	Addition
Project and description	($ million)					
81016: Tools and Equipment – Transmission Engineering Substation	4.9	5.2	6.7	6.7	4.2	4.2
81046: Transmission Construction	0.2	0.2	0.2	0.2	0.2	0.2
81066: Transmission Asset Management program	1.2	1.2	-	-	-	-
81070: Small Tools – Internal Construction Crew	1.1	1.1	1.1	1.1	1.1	1.1
84000: Transportation Equipment	6.7	6.4	7.6	8.9	7.7	7.7
Total	**14.1**	**14.1**	**15.5**	**16.8**	**13.2**	**13.2**

Source: Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, schedules 10-4.
Note: Numbers may not add up due to rounding.

1172. ATCO Electric included a business case for Project 84000. Project 81066 is ATCO Electric's asset management program and is addressed in Section 11.4.3.

1173. The direct general PP&E category of assets was determined on an allocation basis between ATCO Electric transmission and distribution in the previous GTA. ATCO Electric confirmed in its information responses[861] that no "allocated" asset categories would remain after the reorganization.

1174. ATCO Electric provided a note[862] in Schedule 10-4 stating that "[t]he 84000 Transportation Equipment forecast will be revised to $6.7 million in 2015, $3.0 million in 2016 and $2.7 million in 2017; this change will be reflected and modelled during the compliance filing." These proposed revisions would not change forecast expenditures for 2015, but would reduce 2016 forecast expenditures by $4.0 million and 2017 forecast expenditures by $5.0 million.

1175. For comparison, ATCO Electric's direct general PP&E expenditures were $12.1 million, $19.1 million and $17.0 million in 2012, 2013 and 2014, respectively. ATCO Electric's direct general PP&E capital additions were $11.8 million, $17.8 million and $17.5 million in 2012, 2013 and 2014, respectively.

1176. No interveners objected in evidence, argument or reply argument to the forecast amounts.

[861] Exhibit 20272-X0281, AET-AUC-2015JUN08-101, PDF page 214.
[862] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4, line 637.

Commission findings

1177. The Commission finds the total forecast costs for these projects, excluding Project 81066, to be reasonable. The forecast amounts for 2015, 2016, and 2017, as set out in Table 49, are approved, subject to any adjustments that are required to reflect the directions made by the Commission elsewhere in this decision. Commission directions regarding ATCO Electric's asset management program are addressed in Section 11.4.3.

1178. The Commission notes that ATCO Electric has stated that it expects to reduce forecast costs for Project 84000 by $9.0 million in the compliance filing. The Commission directs ATCO Electric to reflect this reduction in the compliance filing, as proposed.

11.4.6 Buildings

1179. ATCO Electric forecast building expenditures and additions as follows:

Table 50. Buildings: forecast capital expenditures and additions for test period

	2015 forecast		2016 forecast		2017 forecast	
	Expenditure	Addition	Expenditure	Addition	Expenditure	Addition
Project and description	($ million)					
82000: Office Furniture	0.3	0.3	0.3	0.3	0.3	0.3
85000: Land, Buildings and Structures	0.5	0.8	1.1	1.1	1.1	1.1
85006: Slave Lake Facility	-	-	4.2	4.2	-	-
85046: Vegreville Land Development	-	0.6	-	-	-	-
85201: General Leasehold Improvements	0.7	1.9	3.9	3.9	4.4	4.4
85202: Leasehold – Building and Floor Rebranding	-	-	0.1	0.1	-	-
85816: Drumheller Service Building - Warehouse Phase I	(0.2)	0.1	-	-	-	-
85820: Peace River Service Building Addition	(0.1)	-	-	-	-	-
85841: Asset Disposition	(0.1)	-	-	-	-	-
85844: Nisku Pole and Training Facility Development	(0.3)	-	-	-	-	-
Total	**0.9**	**3.8**	**9.7**	**9.7**	**5.8**	5.8

Source: Exhibit 20272-X1101, attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, schedule 10-4.
Note: Numbers may not add up due to rounding.

1180. ATCO Electric included a business case for Project 85006.

1181. The buildings category of assets was determined on an allocation basis between ATCO Electric transmission and distribution in the previous GTA. ATCO Electric confirmed in its information responses[863] that no 'allocated' asset categories would remain after the reorganization.

1182. For comparison, ATCO Electric's building expenditures were $33.9 million, $8.0 million and $9.2 million in 2012, 2013 and 2014, respectively. ATCO Electric's buildings capital additions were $48.6 million, $14.2 million and $7.5 million in 2012, 2013 and 2014, respectively.

[863] Exhibit 20272-X0281, AET-AUC-2015JUN08-101, PDF page 214.

1183. General leasehold expenditures for 2012, 2013, and 2014 were $4.8 million, $4.0 million and $4.5 million, respectively.

1184. No interveners raised issues in evidence, argument or reply argument with respect to building related forecast capital costs.

Commission findings

1185. The Commission finds the total forecast costs for these projects to be reasonable. The forecast amounts for 2015, 2016 and 2017, as set out in Table 50 above, are approved, subject to the adjustments that are required to be made to these amounts to reflect the directions made by the Commission elsewhere in this decision.

11.4.7 Net salvage credits

1186. ATCO Electric forecast $14.0 million in 2015, $13.2 million in 2016 and $2.8 million in 2017, for net salvage credits that are applied against the cost of capital additions during the test period.[864]

1187. No interveners addressed these amounts in evidence, argument or reply argument. However, as discussed in Section 8.5 above, the RPG filed evidence, argument and reply argument regarding net salvage rates, generally.

Commission findings

1188. The Commission directs ATCO Electric to update the net salvage credits in Schedule 10-4 in the compliance filing to account for impacts arising from Commission directions elsewhere in the decision.

11.5 Contributions in aid of construction

1189. The contributions in aid of construction (CIAC) forecast is developed based on customer contribution decisions from the AESO or, where such decisions are not yet available, the contribution is calculated based on the AESO's construction contribution policy. ATCO Electric used the currently approved maximum investment levels in developing the forecast and requested that variances between actual and forecast contribution amounts be included in its direct assigned capital projects deferral account.[865] The forecast for CIAC additions is $98.3 million for 2015, $57.0 million for 2016 and $160.7 million for 2017 with retirements, transfers and disposals of -$0.8 million, -$0.5 million and -$1.3 million in 2015, 2016 and 2017 respectively.[866]

1190. No interveners addressed the CIAC forecasts in evidence, argument or reply argument.

Commission findings

1191. The Commission notes that ATCO Electric's proposed treatment of CIAC is the same as that requested in the 2013-2014 GTA which was approved by the Commission in Decision 2013-

[864] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-4: line 445 ($13.8) million plus line 483 ($0.2) million equals ($14.0) million for 2015. Line 630 ($13.1) million plus line 658 ($0.1) million equals ($13.2) million for 2016. Line 630 ($2.7) million plus line 658 ($0.1) million equals ($2.8) million for 2017.
[865] Exhibit 20272-X1099, Attachment 1 – revised application narrative, PDF page 183.
[866] Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-8.

358. The Commission finds ATCO Electric's request that variances between actual and forecast contribution amounts be included in its direct assigned capital projects deferral account to be acceptable, especially considering that this has been the practice in the past, and that the Commission approved the continuation of the direct assigned capital projects deferral account for 2015, 2016 and 2017 in Section 5.4 of this decision. However, the current approval will only apply to the contributions for direct assigned capital projects, and not for any contributions with respect to non-direct assigned capital projects. The Commission considers this to be reasonable because ATCO Electric will take the risk for the contribution forecast for the non-direct assigned capital projects, just as it takes the forecast risk for the capital expenditures and additions for the non-direct assigned capital projects.

1192. For regulatory purposes, a customer contribution is to be accounted for as soon as it is confirmed that a contribution will be required for the project. Waiting until capital expenditures reach a utility's approved investment level in situations where contributions have not yet been received effectively overstates the rate base, and does not recognize the obligation for a customer contribution. This dynamic becomes a matter of particular concern where a customer has already paid a contribution up front, a TFO has incurred capital expenditures, and a number of years have passed before the contribution is recorded as a reduction to rate base. The problem is exacerbated in those instances when the return on CWIP for direct assigned capital projects is included in revenue requirement.

1193. The Commission directs ATCO Electric, in the compliance filing, to provide a list of the 2015 and 2016 actual contribution amounts received, by project, and when any contribution that has been received was paid to ATCO Electric by the customer(s). ATCO Electric is also directed to update the CIAC in Schedule 10-8 to align with Commission directions in Section 11.4.1 of this decision.

11.6 Engineering, supervision and general costs and rates

1194. Engineering, supervision and general (ES&G) costs relate to supporting capital projects and can include the following:

- Costs for drawings.
- Surveys.
- Mapping.
- Project document management.
- Development and maintenance of engineering standards.
- Direct supervision of employees and contractors working on capital projects where the costs are directly attributable to specific projects (including human resource functions, budgeting and forecasting, management team, HS&E, process support and leadership).
- General costs not directly attributable to specific projects such as computer costs, telephone, rent, printing and stationery, small tools, relocation costs, travel and accommodations, training, equipment hours, meals, clerical support, fringe benefits, overtime, vacation.
- Other staff salaries and related costs that are not easily attributable to specific projects.

1195. ATCO Electric provided its current ES&G accounting policy (updated June 1, 2012) in Section 31 – Supplementary Information of its application. In that policy, ATCO Electric stated that "[i]t is the company's policy to include in capital all the costs that relate to the construction

of a capital project. Included in these costs are indirect overhead charges called ES&G that are collected in separate work orders and allocated to capital projects on a monthly basis."[867]

1196. ES&G charges are applicable to non-affiliate capital projects only and are applied to all costs, excluding AFUDC where applicable.[868]

1197. ES&G is analogous to overheads that would normally be charged by a contractor hired to engineer, procure and construct similar projects.

1198. This category of costs is separate from supervision and engineering costs to support O&M which are entered into USA Account 560.[869]

1199. Details of the updated total forecast ES&G costs for 2015, 2016 and 2017, as well as the ES&G rate that is applied to all capital expenditures are included in Schedule 10-6 of the supporting revenue requirement schedules that were filed on February 23, 2016 in conjunction with the updated application.[870] These forecast amounts, including explanations of changes to the forecast amounts between application updates are as follows:

Table 51. Breakdown of engineering, supervision and general estimated costs and rates

Description	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
	($ million)					
Office rent	9.2	9.1	9.9	8.1	5.5	5.7
Administration/safety/training in support of capital work	33.3	33.2	28.2	20.3	19.6	20.0
Increase in training savings due to average training cost and inflation	-	-	-	(0.0)	(0.1)	(0.1)
Computer and IT services	8.9	9.9	8.9	7.7	6.3	6.5
Decrease in IT savings due to average IT cost and inflation / glide path	-	-	-	0.1	0.0	0.0
Supervision & engineering in support of capital work	5.0	3.1	1.8	1.3	1.3	1.3
Workforce reduction - labour and fringe	-	-	-	(0.3)	(3.2)	(3.3)
Reduction in new adds - labour and fringe	-	-	-	-	(0.1)	(0.3)
Vacancy rate adjustment	-	-	-	-	0.3	0.4
Overhead Recoveries offsets						
Alberta PowerLine services	-	-	-	(0.8)	(1.6)	(1.8)
Other	-	-	(1.4)	(0.5)	-	-
Total ES&G (a)	**56.4**	**55.4**	**47.4**	**35.9**	**28.0**	**28.3**
Capital expenditures (b)	1,283.7	1,307.5	1,198.0	369.5	362.9	413.6
ES&G rate (a)/(b-a)	4.6%	4.4%	4.1%	10.8%	8.4%	7.4%

Source: Exhibit 20272-X1101, revised GTA schedules, Schedule 10-6.

1200. ES&G forecasts were decreased in the updated application to reflect a lower workload due to lower forecast capital expenditures.[871] The ES&G rate, however, experiences an increase due to the impact of capital expenditure reductions that are only partially offset by a decrease in

[867] Exhibit 20272-X0003, application, Section 31, PDF pages 9-11.
[868] Exhibit 20272-X0834, AET-CCA-2015JUN08-018(c), PDF page 48.
[869] Exhibit 20272-X0345, AET-CCA-2015JUN08-087(a), PDF page 277.
[870] Exhibit 20272-X1101, attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-6.
[871] Exhibit 20272-X1120, ATCO Electric rebuttal, PDF page 110.

ES&G costs. The relationship between ES&G and capital is not linear and the workload of functional groups in the ES&G category does not directly correspond to capital expenditures.[872]

1201. In testimony, the ATCO Electric witness, Mr. Vachon, clarified that the ES&G rate in Schedule 10-6 is a blend of rates from all projects. Larger projects are treated differently from an ES&G perspective and are subject to a lower ES&G rate because total project costs are of a different magnitude than those for other projects.[873]

1202. The net impact of ES&G IT placeholders to rate base (amounts which are subject to placeholder treatment due to the ongoing IT Common Matters proceeding[874]) is negative $964,916 in 2015, negative $1,475,653 in 2016 and negative $591,694 in 2017.[875]

1203. ATCO Electric confirmed that no labour charges for the WFMAC project were capitalized.[876] ATCO Electric also confirmed that it will charge Alberta PowerLine according to the ATCO Group Inter-Affiliate Code of Conduct on a cost recovery basis, including O&M and ES&G overhead rates.[877] In practice, the overhead charge to Alberta Powerline includes ES&G which is then removed from Schedule 10-6 because it is charged directly to a specific project to ensure that the costs are not charged to other projects.[878] ES&G charges related to the WFMAC project are addressed further in Section 16.1 below as part of the affiliate overhead rate applied to labour costs for constructions projects.

1204. ATCO Electric is able to deduct certain costs for income tax purposes which are directly incurred as part of a capital project and certain indirectly charged ES&G costs that meet the same criteria.[879] In argument, the RPG noted that the DACDA process does not true up variances in ES&G or removal and abandonment costs for income tax purposes. It simply includes the costs in the review of overall capital additions so that actual ES&G and removal and abandonment costs flow into opening rate base once approved and the variance flows permanently to ATCO Electric. The RPG argued that in the last test year, ATCO Electric under-forecast the temporary differences from ES&G and removal and abandonment costs by $73.7 million.[880] ES&G deductions for income tax purposes are addressed further in the income tax section (Section 9) of this decision.

1205. The RPG did not have any specific recommendations with respect to the forecast for ES&G. However, it did note that the applied-for ES&G rates are greater than actual rates from 2013 and 2014. The RPG did not support the ES&G rates "forecast within this application and will fully review and assess all amounts charged to capital projects in the future as part of the DACDA or a review of opening base in a future GTA."[881]

[872] Exhibit 20272-X630, AET-CCA-2015OCT16-011, PDF pages 51-52.
[873] Transcript, Volume 9, page 1574.
[874] Proceeding 20514, ATCO Utilities IT common matters proceeding.
[875] Exhibit 20272-X1063, AET-AUC-2015JUN08-006 Attachment 2 revised.
[876] Exhibit 20272-X0623, AET-AUC-2015OCT16-004(e), PDF page 13.
[877] Exhibit 20272-X0284, AET-AUC-2015JUN08-019(j), PDF page 655.
[878] Transcript, Volume 8, page 1340.
[879] Exhibit 20272-X0348, AET-CCA-2015JUN08-018(a), PDF page 46.
[880] Exhibit 20272-X1297, RPG argument, PDF page 137.
[881] Exhibit 20272-X1297, RPG argument, PDF page 185.

Commission findings

1206. The forecast for total ES&G costs in the test period may be affected by other directions included in this decision, as will the resulting ES&G rate. The Commission directs ATCO Electric, in the compliance filing, to update the total forecast ES&G costs and rates for the test period, as necessary, to reflect all applicable directions included in this decision.

11.7 Retirements and adjustments for PP&E

1207. ATCO Electric forecast retirements and adjustment costs for 2015 of $22.3 million, $31.4 million for 2016 and $3.0 million for 2017[882] with accumulated depreciation adjustments of $35.5 million in 2015, $38.5 million in 2016 and $5.0 million in 2017.[883]

1208. ATCO Electric provided its current accounting policy for disposals and retirements (updated September 9, 2014) in Section 31 – Supplementary Information of its application. The purpose of the policy is to describe the accounting treatment for retirement of fixed assets when they have been replaced and/or removed from service, sold, decommissioned or destroyed due to accident. Where applicable, the policy differentiates the treatment per IFRS standards and treatment for regulatory accounting.[884]

1209. No interveners addressed the retirement and adjustment forecasts in evidence, argument or reply argument.

Commission findings

1210. The actual retirements were $3.9 million in 2012, $18.1 million in 2013 and $14.8 million in 2014.[885] The significant differences in actual retirements during these years demonstrates the inherent variability in the timing of retirements, and suggests that arriving at an accurate forecast is difficult. The 2015, 2016 and 2017 amounts are at levels consistent with past actuals. Accordingly, the Commission approves the forecast retirements.

1211. The actual accumulated depreciation adjustments were $6.4 million in 2012, $19.1 million in 2013 and $39.8 million in 2014.[886] Like the actual retirements discussed above, these intertemporal variations demonstrate the inherent variability in these adjustments, and suggests that arriving at an accurate forecast is difficult. The 2015, 2016 and 2017 amounts are at levels consistent with past actuals. Accordingly, the Commission approves the forecast accumulated depreciation adjustments subject to any directed adjustments elsewhere in this decision which affect these amounts.

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882 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-2, sum of lines 12-15.
883 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-3, sum of lines 12-13.
884 Exhibit 20272-X0003, application, Section 31, PDF pages 7-8.
885 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-2, sum of lines 12-15.
886 Exhibit 20272-X1101, Attachment 2, 2015-2017 GTA schedules revised Feb 23, 2016, Schedule 10-3, sum of lines 12-13.

12 Necessary working capital

1212. Necessary working capital is included as an increase to total rate base when payment of expenses occurs in advance of the receipt of revenues.

1213. In the application, ATCO Electric explained that it had reviewed each component of necessary working capital items to ensure that the nature of the revenues and expenses included in each category had not materially changed since the previous lead/lag study was prepared. After concluding that a new lead/lag study was not required, it applied the 2010 study lead/lag days that were approved in its 2013-2014 GTA to the 2013 actual revenues and operating expenses to calculate the net operating expense lag used for the necessary working capital calculation in its current application.[887]

1214. The updated weighted revenue lag days based on the 2013 actual revenues were then applied to the 2010 study results for income tax, depreciation, interest expense, preferred equity and common equity to determine the net lag days for these components of working capital. ATCO Electric stated that these components had slight changes to their lag days due to the change in revenue lag days, but that the impact on necessary working capital was a direct result of the increase in rate base during the test period.[888]

1215. ATCO Electric stated that the net operating expense lag days had changed from 28.0 days to 30.2 days. The 2013 actual expense dollars for the Parent Charges category increased while the dollars in Other decreased when compared to the 2010 expenses. This, in turn, contributed to a decrease in operating expense lag due to the difference in weightings from the expense category of Other, with lead/lag days of 44.1, to Parent Charges with lead/lag days of 20.1. While this resulted in a decrease in net operating expense lag days, the net operating expense component of working capital increased overall for the test period due to the increased level of O&M expenses during that period.[889]

1216. A summary of the proposed necessary working capital by component is shown in the table below:

[887] Exhibit 20272-X1100, application, paragraphs 453-454, PDF page 356.
[888] Exhibit 20272-X1100, application, paragraph 457, PDF page 357.
[889] Exhibit 20272-X1100, application, paragraph 456, PDF page 357.

Table 52. Summary of Transmission necessary working capital

Description	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
	($ million)					
Operating expense	8.6	8.5	9.4	15.9	17.0	18.9
Income tax expense	2.1	2.0	(1.2)	2.5	3.7	4.0
Materials & supplies inventory	1.9	2.3	2.1	2.5	3.1	3.2
Rate case expense	0.5	1.0	1.8	2.1	1.1	0.2
Goods & services tax	1.2	1.1	1.0	0.2	0.3	0.3
Depreciation expense	9.4	12.1	15.2	26.2	36.5	37.9
Unamortized debt costs	7.0	10.2	13.7	16.3	16.9	16.8
Unamortized preferred share costs	1.5	1.0	0.5	0.2	0.0	0.0
Interest expense	(9.7)	(13.3)	(17.2)	(19.0)	(19.1)	(19.3)
Preferred equity	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Common equity (retained earnings component)	6.2	8.1	9.2	9.5	9.6	9.5
Common equity (dividend component)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Total necessary working capital	28.7	32.7	34.2	56.2	68.9	71.5

Source: Based on Exhibit 20272-X1101, Schedule 11-1 Transmission Necessary Working Capital.

1217. The RPG expressed concern over the amounts being proposed by ATCO Electric for necessary working capital. The RPG commented that the material depreciation increases were driven by the depreciation parameters being requested, and not by a change in depreciation lag days.[890] The RPG addressed these proposed depreciation parameters separately in the depreciation section.

1218. With regard to the submitted operating costs, the RPG challenged ATCO Electric's use of total operating costs, which included the staff costs being allocated to Alberta Powerline and other affiliates. The RPG submitted that revenue offsets for these affiliate charges, amounting to $25.5 million in 2015, $12.5 million in 2016 and $10.7 million in 2017,[891] should be reflected as a downward adjustment to the operating costs being used to avoid inflating the necessary working capital related to O&M. Further, the RPG argued that costs which are not subject to the normal lag days as normal operating costs, such as severance costs, should also be excluded as they further inflate operating costs.[892]

1219. The RPG recommended that the Commission direct ATCO Electric to refile its working capital to exclude all operating costs related to affiliates, to exclude abnormal items such as severance costs, and to reduce its lag days to 28.0 from 30.2 for operating costs.[893]

1220. ATCO Electric rejected the RPG's recommendations to reduce the number of lag days for operating costs from 30.2 to 28.0, stating that the calculation ATCO Electric provided supported the 30.2 days. Further, the costs for affiliates and severance are actual incurred

[890] Exhibit 20272-X1297, RPG argument, paragraph 600, PDF pages 185-186.
[891] Exhibit 20272-X1101, ATCO Electric GTA Schedules, Schedule 5-3.
[892] Exhibit 20272-X1297, RPG argument, paragraphs 601-602, PDF page 186.
[893] Exhibit 20272-X1297, RPG argument, paragraph 603, PDF page 186.

operating costs which are properly included in the working capital calculation and the RPG provided no supporting evidence to justify their exclusion.

Commission findings

1221. The Commission observes that the majority of the increases to necessary working capital for the test period are driven by levels of depreciation expense and operating expense ATCO Electric proposed for the test years.

1222. With regard to depreciation expense, the Commission notes that the depreciation lag days increased from 44.9 days for 2014 to 45.0 days for the test period, and have not materially changed for the necessary working capital calculation. The proposed level of net depreciation expense used for the calculation, however, has materially increased resulting in the largest component increase to necessary working capital, as shown in the table below:

Table 53. Transmission necessary working capital depreciation calculation

Description	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
	($ million)					
Net depreciation	76.2	98.0	123.3	212.2	296.4	307.5
Depreciation lag days	45.0	44.9	44.9	45.0	45.0	45.0
Depreciation working capital	9.4	12.1	15.2	26.2	36.5	37.9

Source: Based on Exhibit 20272-X1101, Schedule 11-2 Transmission Necessary Working Capital Calculation.

1223. The Commission's determinations on the level of net depreciation are found in Section 8 of this decision. The Commission directs ATCO Electric, in the compliance filing, to reflect all findings and determinations which affect the net depreciation used in the necessary working capital calculations.

1224. ATCO Electric proposed material increases to the operating expense component of necessary working capital. It submitted that the operating expense component increase is mainly driven by the proposed level of operating expense over the test years, as shown in the table below:

Table 54. Transmission necessary working capital operating expense calculation

Description	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
	($ million)					
Total fuel & operating costs	110.4	111.4	123.1	193.2	206.1	229.3
Less: provision for injuries and damages	(0.3)	(1.0)	(1.0)	(0.7)	(0.7)	(0.7)
Net O&M	110.1	110.3	122.1	192.5	205.4	228.6
O&M lag days	28.6	28.0	28.0	30.2	30.2	30.2
Cash operating expenses working capital	8.6	8.5	9.4	15.9	17.0	18.9

Source: Based on Exhibit 20272-X1101, Schedule 11-2 Transmission Necessary Working Capital Calculation.

1225. The Commission's determinations on the level of operating expenses are found in Section 7 of this decision. The Commission directs ATCO Electric, in the compliance filing, to reflect all

findings and determinations which affect the operating expenses used in the necessary working capital calculations.

1226. The RPG challenged ATCO Electric's use of total operating costs for the necessary working capital calculation because it included costs related to work being done for affiliates, which are reimbursed through the use of revenue offsets. The Commission notes that the amount of affiliate work that is included in the transmission expense included in this category is material, as shown by the affiliate cost of goods sold summarized in the table below:

Table 55. Details of affiliate cost of goods sold included in Transmission expense – Account 566

Description	2012 actual	2013 actual	2014 actual	Test period		
				2015	2016	2017
	($ million)					
Affiliate cost of goods sold						
Affiliate cost of goods sold - WFMAC affiliate services	-	-	-	4.3	8.1	8.9
Affiliate cost of goods sold - other	0.4	0.5	1.3	21.2	4.3	1.8
Total affiliate cost of goods sold	0.4	0.5	1.3	25.5	12.5	10.7
Affiliate cost of goods sold overhead recovery						
Overhead recovery - WFMAC affiliate services	-	-	-	(0.9)	(1.7)	(1.9)
Overhead recovery - other	(0.1)	(0.2)	(1.5)	(1.8)	(1.0)	(0.5)
Total affiliate cost of goods sold overhead recovery	(0.1)	(0.2)	(1.5)	(2.7)	(2.7)	(2.4)

Source: Based on Exhibit 20272-X1101, Schedule 5-3 Details of Miscellaneous Transmission Expense – Account 566.

1227. In the application, ATCO Electric stated that the "Affiliate Cost of Goods Sold is offset by Affiliate Revenues and will have no material impact on revenue requirement."[894] The Commission considers that on a forecast basis the affiliate revenues may offset the affiliate cost of goods sold included as transmission expense. However, including these affiliate costs in the calculation of the operating expense component of necessary working capital does affect the necessary working capital calculation for operating expense and, therefore, also affects revenue requirement through its inclusion in rate base. The Commission, therefore, directs ATCO Electric, in the compliance filing, to reduce the total fuel & operating costs used in the necessary working capital calculation for operating expense by the total affiliate cost of goods sold for each of the test years. The Commission will not, however, reduce the amount of the operating expense adjustment by the affiliate cost of goods sold overhead recovery shown in Table 55 above because it represents a separate recovery of overhead costs which are less direct in nature. This amount will therefore remain as a reduction to the operating expense total used for the calculation to ensure affiliate related overhead costs are not included in the revenue requirement.

1228. The Commission is not persuaded by the RPG's submission that costs which are not subject to normal lag days as normal operating costs (e.g., severance costs), should be excluded from the operating expense used for the necessary working capital calculations,. The RPG did not provide sufficient evidence to support its position, which otherwise might have clarified what operating costs would specifically warrant an adjustment or, alternatively, be considered a

[894] Exhibit 20272-X1101, Schedule 5-3 Details of Miscellaneous Transmission Expense – Account 566, Note 6.

"normal" operating cost. The Commission finds that the RPG's proposal to reduce the net operating expense lag days to 28.0 days from 30.2 days was similarly unsupported. For these reasons, the Commission rejects these proposals.

1229. While ATCO Electric explained that it had reviewed the working capital components and had determined that a new lead/lag study was not required, the Commission notes that the 2010 study used for the current proceeding had originally been prepared for the utility's 2013-2014 GTA. In this application, ATCO Electric applied its results to the 2013 actual revenues and operating expenses to calculate the net operating expense lag used in the present necessary working capital calculation.

1230. The Commission notes that a three-year test period was proposed by ATCO Electric and that a 2010 study was used for the current application. The Commission considers that a new lead/lag study would have facilitated a more comprehensive review of all working capital components and days relied upon in the current proceeding, and would have facilitated better testing of impacts resulting from changes occurring since the last study was prepared.

1231. For the above reasons, the Commission directs ATCO Electric to prepare and file an updated comprehensive lead/lag study as part of its next GTA application.

13 Isolated generation operating costs

1232. ATCO Electric forecast isolated operations and maintenance for 2015 to 2017 as follows:

Table 56. Isolated generation operation and maintenance expense by account

Description		Test period		
		2015	2016	2017
		($ million)		
Hydraulic power generation				
537	Hydro expenses	0.1	0.1	0.1
Other power generation and supply expenses				
546	Combustion engines/turbine operations	3.1	4.2	4.5
554	Combustion engines/turbine maintenance	1.9	2.7	3.0
557	Other expenses	1.1	1.5	1.6
	Total	6.2	8.6	9.3

Source: Based on Exhibit 20272-X1101, revised application with GTA schedules, Schedule 22-1.

1233. No party took issue with ATCO Electric's forecast of its isolated generation operations and maintenance costs.

Commission findings

1234. In ATCO Electric's revised application, filed on February 23, 2016, the utility provided the following summary of emergency mobile generating units in its fleet:

Table 57. Summary of emergency mobile generating unit fleet

	Emergency mobile generating units (as identified in the *Isolated Generating Units and Customer Choice Regulation*)	Manufacturing year	Number of generating units	Total capacity (kW)
1	Unit # 331	1990	1	1,000
2	Unit # 360	1999	1	1,000
3	Unit # 433	2003	1	430
4	Unit # 316	1990	1	430
5	Unit # 338	1991	1	430
6	Unit # 366	1998	1	430
7	Unit # 306	1990	1	140
8	Unit # 307	1990	1	140
9	Unit # 308	1990	1	140
10	Unit # 309	1990	1	140
		Total	10	4,280

Source: Based on Exhibit 20272-X1100, Table 22.4 – Emergency Mobile Generating Unit Fleet, paragraph 465.

1235. On July 17, 2015, ATCO Electric filed an application with the Alberta Utilities Commission seeking approval to dispose of mobile generating unit CUL 307 under Section 13 of the *Isolated Generating Units and Customer Choice Regulation*, AR 165/2003, and to strike mobile generating unit CUL 307 from Part C of the Schedule to the regulation.[895]

1236. In Decision 20634-D01-2015,[896] the Commission provided ATCO Electric with the following direction:[897]

> 13. Based on the above, the Commission finds that mobile generating unit CUL 307 is no longer required to provide a reliable supply of electric energy to an isolated community or industrial area. The Commission is satisfied that mobile generating unit CUL 307 will be decommissioned as of December 31, 2015, and used for spare parts for other similar units. This date is set out in Decision 20038-D02-2015[[898]] for completion of the alteration of the power plant at Steen River. Accordingly, mobile generating unit CUL 307 is struck from Part C of the Schedule to the *Isolated Generating Units and Customer Choice Regulation*, and all costs associated with the unit are to be removed from any tariff to be approved for 2016 and any subsequent years.

1237. ATCO Electric is to confirm, in the compliance filing to this decision, that it has removed mobile unit number 307 from Part C of the Schedule to the *Isolated Generating Units and Customer Choice Regulation*, and that all costs relating to this mobile unit have been removed from its 2016 and 2017 test period forecast amounts.

1238. The Commission approves the isolated operations and maintenance test period forecasts as filed subject to any adjustments that may be required in relation to directions contained in other sections of this decision.

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[895] Exhibit 20634-X0001, paragraph 3, page 1. This mobile unit is listed in Part C of the schedule to the regulation as an isolated generating unit.

[896] Decision 20634-D01-2015: ATCO Electric Ltd., Application for Removal of CUL 307 from Isolated Generating Units Inventory, Proceeding 20634, October 2, 2015.

[897] Decision 20634-D01-2015, paragraph 13.

[898] Power Plant Approval 20038-D02-2015: Appendix 1 to Decision 20038-D01-2015, ATCO Electric Ltd., Time Extension to Alter Steen River Power Plant, Proceeding 20038, Application 20038-A001, January 16, 2015.

14 Corporate administration and general

1239. ATCO Electric submitted the following schedule in its final update providing a history of actual expenses and its requests for the test years:

Table 58. Schedule of corporate administration and general expense by account

Line no.	Acct nos.	Description	Cross reference	2012 actual	2013 actual	2014 actual	Test period 2015	2016	2017
				($ million)					
1	**Corporate administration and general**								
2									
3	920	General administration	S. 25-2	5.8	6.8	6.0	9.9	10.6	11.3
4	921	Office supplies and expenses	S. 25-2	4.7	5.6	7.1	20.7	8.8	10.5
5	923	Outside services employed	S. 25-2	1.6	0.8	0.6	2.2	2.3	2.4
6	924	Insurance premiums	S. 25-3	1.7	2.0	2.8	3.7	14.5	15.1
7	925	Injuries and damages	S. 29-2	0.3	1.0	1.0	0.7	0.7	0.7
8	928	Commission expenses	S. 25-10	0.4	0.4	0.4	2.6	2.6	2.6
9	930.2	Miscellaneous general expenses	S. 25-3	9.0	7.6	8.6	12.3	14.7	16.9
10	931.1	Head office rent	S. 25-3	1.5	2.5	1.0	2.3	2.5	2.5
11	934	IT G&A expense	S. 25-3	2.1	2.5	3.0	3.8	4.5	5.3
12	941	Commission expenses disallowed	S. 25-3	0.1	0.7	1.0	0.6	0.6	0.6
13	935.2	Maintenance company-owned houses	S. 25-3	0.5	0.3	0.2	-	-	-
14									
15	**Function total**			27.7	30.2	31.6	**58.7**	**61.6**	**67.8**
16									
17	**Less: costs not included in revenue requirement**								
18		Donations		(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)
19		Earnings based executive compensation		(0.0)	(0.0)	-	(0.1)	(0.1)	(0.1)
20		Disallowed head office costs	Note 1	(0.1)	(0.1)	(0.2)	-	-	-
21		Corporate signature rights		(1.0)	(1.5)	(2.5)	-	-	-
22		Disallowed aircraft		(0.4)	(0.2)	(0.5)	-	-	-
23		Legal cost in excess of board scale		(0.1)	(0.8)	(1.0)	(0.6)	(0.6)	(0.6)
24		Pension - COLA		(0.2)	(1.3)	(0.3)	(0.3)	(0.3)	(0.3)
25		IT cost reduction		-	-	(0.5)	-	-	-
26									
27	**Total administration and general**		Note 2	25.4	25.7	25.9	**57.1**	**59.9**	**66.1**

Note 1: The allocated head office costs to ATCO Electric exclude any non-utility items.
Note 2: The following costs have been remapped to corporate from common and general operations and have been included in the totals above to provide year over year comparability.
Source: Exhibit 20272-X1101, Attachment 2 - 2015-2017 GTA Schedules - Revised Feb 23, 2016, Schedule 25-1.

1240. The Commission will review the expenses for all the costs contained in the above table immediately below. However, it will deal with USA accounts 924 and 925 separately in sections 14.1 and 14.2, respectively, to address ATCO Electric's specific requests.

1241. The RPG argued that increases in administrative costs beyond inflation and growth, if experienced by a company operating in a competitive marketplace, would impair that company's overall competitiveness. Although the RPG conceded that cost increases are to some extent

inevitable, it does not agree that the increased administration and general (A&G) expenses forecast by ATCO Electric are justifiable in the regulated world.[899]

1242. The RPG identified concerns with respect to specific amounts included in corporate administration and general USA codes and made the recommendations noted below. The recommendations were in addition to the RPG's broader recommendations to disallow a portion of all of the utility's operating expenses, given ATCO Electric's historical forecasting inaccuracy.[900]

1243. The RPG had no specific recommendations with respect to the following accounts:

USA Code 921 – Office Supplies and Expenses
USA Code 928 – Commission Expenses
USA Code 931.1 – Head Office Rent
USA Code 934 – IT G&A Expense

1244. The RPG did have recommendations with respect to the identified accounts as follows:

> USA Code 920 - General Administration
>
> Since the test year forecast of expenses for USA code 920 exceed the expense level expected based on growth and inflation in each of the test years and given the lack of support for at least $2 million increase in 2015, the Ratepayer group recommends that USA code 920 increases be reduced by at least $2 million (i.e. $1.4m plus $0.6million) in 2015. The same reduction should be applied to 2016 and 2017 since the expense levels in these two years simply build on the 2015 expense level.[901]
>
> USA Code 923 – Outside Services Employed
>
> Given the lack of justification for the materially increased costs based on program changes, the Ratepayer Group recommends that account 923 increases in 2015 be reduced by $1.2M (i.e. $2.2M minus $1.0M average of 2012 to 2014). The same reduction should be applied to 2016 and 2017 since the expense levels in these two years simply build on the 2015 expense level.[902]
>
> USA Code 930.2 – Miscellaneous General Expenses
>
> In summary the Ratepayer Group recommends the following:
>
> > i. AET be directed to provide appropriate metrics to demonstrate total head office costs are reasonable in relation to growth, inflation and any other relevant factors at the time of the next GTA;
> > ii. The total head office cost for 2015 be reduced to $58.2M; and
> > iii. AET's Head office costs in each of the test years be reduced by $0.3M.[903]

[899] Exhibit 20272-X1297, RPG argument, paragraph 291, PDF page 101.
[900] Exhibit 20272-X1297, RPG argument, paragraph 605, PDF page 186.
[901] Exhibit 20272-X1297, RPG argument, paragraph 619, PDF page 190.
[902] Exhibit 20272-X1297, RPG argument, paragraph 628, PDF page 192.
[903] Exhibit 20272-X1297, RPG argument, paragraph 652, PDF page 197.

1245. ATCO Electric argued that the RPG had not provided evidence regarding ATCO Electric's head office expenses and that its conclusion that increases should be in line with inflation and growth was mentioned for the first time in argument.

1246. ATCO Electric submitted that it had provided complete explanations for the requested increases, and that these forecast increases had not been successfully challenged by the RPG. It submitted that the RPG's recommendation to deny recovery of its expenses should be rejected.[904]

Commission findings

1247. In reviewing the RPG's recommendations, the Commission noted a possible error in the RPG's calculations. For example, the RPG recommended that total expenses be limited to $58.2 million in 2015 and that expenses for accounts 920, 923 and 930.2 be reduced by $3.5 million ($2.0 million for account 920, $1.2 million for account 923 and $0.3 million for account 930.2). However, when the Commission applied the recommended reductions to the totals provided in ATCO Electric's updated Schedule 25-1, it obtained a reduced total of $53.6 million, being the difference between the submitted total forecast of $57.1 million and the RPG's recommended reduction of $3.5 million.

1248. The Commission's analysis shows that expenses increased by 75 per cent in 2015 over 2014 levels after the severance of $11.8 million in account 921 in 2015 is excluded.[905] Excluding the severance in 2015 and the placeholder of $10 million for insurance in each of 2016 and 2017, ATCO Electric's expenses are forecast to increase by 10 per cent in 2016 over 2015. The increase in 2017 over 2016 is currently calculated as 12 per cent and the average for the three test years is 32 per cent per year.

1249. The Commission finds that the forecast increases in A&G costs are, on the whole, unusually large. The Commission finds that the provided forecasts do not lie within a reasonable range and that the methodology used to generate them is likewise unreasonable. The Commission accepts the RPG's recommended reductions in each test year of $2 million, $1.2 million and $0.3 million for USA accounts 920, 923 and 930.2, respectively. In addition, the Commission expects ATCO Electric to apply the same global percentage reductions to corporate A&G expenses as may be applied to operating expenses as determined elsewhere in this decision. The Commission directs ATCO Electric to provide all changes as noted, in its compliance filing.

14.1 Insurance costs

1250. ATCO Electric submitted a request for the approval of a placeholder relating to forecast costs in obtaining third-party line insurance during the test period.

1251. ATCO Electric indicated in Schedule 25-1 of the application that it was seeking approval of a placeholder of approximately $10 million per year for each of 2016 and 2017 to cover line insurance costs. The utility proposed that these placeholders would be replaced by the actual costs of line insurance once these amounts were finalized.

[904] Exhibit 20272-X1309, ATCO Electric Transmission reply argument, paragraph 253, pages 102-103.
[905] (57.1-11.8-25.9)/25.9*100= 75%.

1252. During the oral hearing, ATCO Electric's witness, Mr. DeChamplain, explained that the impact of Decision 2013-417[906] (the UAD decision) was to create a gap in ATCO Electric 's insurance coverage. Prior to the UAD decision, ATCO Electric had relied on the reserve for injuries and damages (RID) to deal with what is now considered an "extraordinary retirement," as that term is used in the UAD decision; not a sale as in the *Stores Block*[907] case but, rather, the destruction of an asset by fire, flood or storm in circumstances amounting to an "extraordinary retirement." The ATCO Electric witness stated that the company now finds itself bearing more risk without the corresponding benefit of a higher allowed rate of return on equity to reflect the additional costs associated with that greater risk. Mr. DeChamplain expressly noted that no allowance for a higher return on equity was granted by the Commission in its most recent generic cost of capital decision to account for the increased risk the company now faces. As a result, the company now faces a gap in recovering its prudently incurred costs. "The trigger, which would be an extraordinary retirement, if it's not caught through depreciation rates, would result in a loss to share owners – or to the business, and any business would insure its assets to mitigate any potential losses, much like we were back in the old days."[908]

1253. The RPG submitted that the approval of a placeholder for the cost of line insurance would be inconsistent with existing Commission precedents regarding utility asset dispositions. It argued that the Commission should exclude these amounts from revenue requirement as they are not a customer cost. The RPG further argued that it would be improper for customers to pay for insurance costs incurred to provide coverage for losses that would otherwise be ineligible for recovery through the utility's RID account.[909]

1254. The RPG maintained that the entire $10 million proposed to be afforded placeholder treatment for insurance costs in each of 2016 and 2017 would be incurred to provide coverage for losses arising from natural disasters and other accidental events including fires, storms, floods, etc. In its view, existing Commission precedent requires that shareholders bear the risks attending these kinds of events. Consequently, shareholders, and not customers, must bear any costs associated with attempts to limit exposure to the financial consequences of such occurrences.

1255. The RPG also submitted that, in any event, the Commission might consider expanding the definition of retirements in the ordinary course of business to include natural disasters and accidental insurable events such as fires, storms, etc. to permit costs associated with such losses to be recoverable through the utility's existing RID mechanism. The RPG submitted that no changes to the existing RID provision for the test period would be required if the Commission chose to pursue this option "since the provision duly reflects a 5-year history of claims to the RID account."[910]

1256. The UCA submitted that any purported UAD-associated risk does not affect the ability of utilities, including ATCO Electric, to earn a fair return. The UCA questioned why the cost of

[906] Decision 2013-417: Utility Asset Disposition, Application No. 1566373, Proceeding 20, November 26. 2013, appeal denied *FortisAlberta Inc. v. Alberta (Utilities Commission), 2015 ABCA 295, 389 DLR (4th) 1,* leave to appeal refused*, SCC File No. 36728 (UAD).*

[907] *ATCO Gas and Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4, [2006] 1 S.C.R. 140. (*Stores Block*)

[908] Transcript, Volume 10, pages 1662-1665.

[909] Exhibit 20272-X1297, RPG argument, paragraph 630, PDF page 192.

[910] Exhibit 20272-X1297, RPG argument, paragraph 634, PDF page 193.

insurance to protect shareholders from risks associated with the loss of utility property should be included in customer rates.

1257. The UCA argued that insuring against a non-existent or negligible risk was not prudent. However, it also stated that, in the event that line insurance costs are included in customer rates, they should be subject to deferral account treatment to ensure that customers only pay for the actual costs incurred by ATCO Electric.[911]

1258. ATCO Electric argued it was "seeking to protect itself from the costs associated with 'insurable events' that have historically been covered either through third party line insurance policies or through the RID. At no point did ATCO Electric assume the risk associated with losses arising from such insurable events. This had always been the case until the recent AUC Decision regarding AED's Slave Lake assets (Decision 2014-297 (Errata))[912] which denied recovery through the RID."[913]

1259. In argument ATCO Electric stated the following:[914]

> 90. As explained in Information Response AET-AUC-20150CT16-017(a) (Ex. 0620) AET is seeking to reinstitute third party line insurance to address a gap that has recently been created in the coverage historically provided to it by either third party insurance or the Reserve for Injuries and Damages ("RID") for a risk it has never previously assumed (8T1303-1306). Additionally, the costs of line insurance reflect prudently incurred costs and AET historically recovered such insurance costs prior to the AUC's Direction to utilize the RID for this purpose. AET also notes that it prudently insures its other assets and the costs thereof are recoverable in Revenue Requirement. This is consistent with the historic treatment of these costs by the AUC.
>
> 91. As noted by AET, prior to June 2008 it purchased third party line insurance and, in the event of damage to an AET line, it recovered the costs associated with these insurable events from such third party insurance. During this time the deductible portion of such insurance was charged to ratepayers through the RID. In addition, in the event that the insurance proceeds were not sufficient to cover the replacement or repair any excess costs were charged to the RID. As a result, AET was held whole regarding these insurable events and no costs were absorbed by shareholders.
>
> 92. Subsequent to June 2008 and based on the AUC's Direction in Decision 2007-071[915] AET moved to a self-insurance model for its transmission line assets rather than paying third party insurance premiums. Under this arrangement, if an insurable event occurred, the RID was charged with the total cost to repair or replace the damaged asset. Once again, AET's shareholders were not at risk for any of the costs associated with these insurable events. As such, it cannot be argued that this was a risk that was previously assumed by AET's shareholders or that was covered by or recovered in the return awarded to AET in past periods (10T1660-1664).

911 Exhibit 20272-X1296, UCA argument, paragraphs 59-60, PDF pages 29-30.
912 Decision 2014-297 (Errata): ATCO Electric Ltd., 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 2682, October 29, 2014. Errata issued January 8, 2015.
913 Exhibit 20272-X1298, ATCO Electric argument, paragraph 27, PDF page 20.
914 Exhibit 20272-X1298, ATCO Electric argument, paragraphs 90-93, PDF pages 45-46.
915 Decision 2007-071: ATCO Electric Ltd., 2007-2008 General Tariff Application – Phase I, Application 1485740-1, September 22, 2007.

> 93. However, recent AUC Decisions (including specifically the Slave Lake Decision — No. 2014-297 (Errata), p. 12-19) have created a "gap" in the coverage that previously existed, such that AET shareholders are now potentially at risk for costs associated with such insurable events. The full protection previously available via self-insurance and AET's depreciation practices is apparently no longer available or has been significantly reduced. Therefore, AET is required to take reasonable and prudent steps to address and mitigate this new risk. AET's proposed treatment ensures continued fair treatment for all parties.

Commission findings

1260. The Commission will not permit the requested line insurance cost placeholder amounts to be included in ATCO Electric's revenue requirement for the test period. ATCO Electric stated that the proposed line insurance was intended to protect its shareholders in the event of an "extraordinary loss" to shareholder owned assets. This being the case, any costs incurred to manage the shareholders' risk associated with the loss of ATCO Electric's assets must be borne by shareholders and not customers.

1261. In the UAD decision, the Commission undertook an extensive review and analysis of the impact in Alberta of the Supreme Court of Canada's *Stores Block* decision and subsequent Alberta Court of Appeal decisions on the financial consequences of utility asset dispositions and other circumstances where assets cease to be used or required to be used in providing utility service. In the UAD decision, the Commission determined that application of the common law principles reviewed by the majority of the court in *Stores Block* dictated that utilities, as the legal owners of utility assets, are both entitled to the benefits and exposed to the liabilities flowing from such ownership. One of the consequences of this analysis is that utility customers do not, and cannot, possess an insurable interest in this property.

1262. The Commission considers that requiring ratepayers to fund an indemnification mechanism that protects the shareholders from the risk of loss of assets in which customers have no insurable interest would be at odds with the symmetrical application of the common law principles discussed in *Stores Block.* The Commission does not consider that the regulatory compact in Alberta dictates that ATCO Electric "[be] held whole regarding these insurable events and no costs [be] absorbed by shareholders."

1263. Expanding the range of RID-eligible casualty-associated events to include those that would otherwise constitute extraordinary retirements would be inconsistent with both the UAD decision and the Commission's past application of the principles described in it. The Commission finds that its current interpretation of the scope of RID eligibility is, in contrast, consistent with both the UAD decision and the depreciation principles underlying modern utility accounting. As the Commission explained in Decision 2014-297 (Errata) (the Slave Lake decision):

> 66. The UAD decision recognized the concepts underlying the currently-used depreciation methods as being consistent with the *Stores Block* principles because they are intended to recover the costs of assets used in utility service over their service lives in ordinary circumstances, recognizing that retirements outside the relevant scope of considered retirement events, regardless of the effect on depreciation parameters, would be classified as extraordinary retirements, and in accordance with *Stores Block* principles, would be for the shareholders' account.

1264. The Commission does not consider that its refusal to permit third party line insurance costs to be included in ATCO Electric's revenue requirement adversely affects the utility's ability to earn a fair return for its shareholders. The Commission determines the fair return for ATCO Electric in accordance with its established generic cost of capital (GCOC) process. ATCO Electric was one of several Alberta utilities that requested an adjustment to its approved return on equity (ROE) in the 2013 GCOC proceeding to compensate it for what it perceived to be additional uncertainty arising from the Commission's adoption of UAD principles. The Commission ultimately declined to make the requested adjustment:

> 346. …the Commission finds that, insofar as [the] issuance of the *Stores Block* and related line of decisions may have impacted the risk profile of Alberta utilities, the fact that these [decisions] may have resulted in the probabilities of over- or under-earning relative to their allowed returns being other than equal is not sufficient to require the allowance of a premium on ROE in order to satisfy the fair return standard.
>
> …
>
> 351. In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.[916]

1265. Proceeding from similar reasoning, the Commission considers that its decision in this proceeding to exclude third-party line insurance costs from ATCO Electric's revenue requirement does not materially impair the utility's ability to earn a fair return for its investors. Further, and in any event, the Commission is reviewing ATCO Electric's permitted return on equity and deemed capital structure in the current 2016 GCOC proceeding (Proceeding 20622).

1266. The Commission rejects ATCO Electric's argument that, in light of the Commission's recent decisions applying UAD principles, prudence dictates that the utility must charge its customers the cost of obtaining third-party line insurance. ATCO Electric has a responsibility to provide safe and reliable service to its customers; it is also entitled to a reasonable opportunity to recover the costs it incurs in doing so. However, property rights in prudently acquired assets rest with their legal owner, the utility (and, by extension, its shareholders). The Commission finds that it is reasonable that the cost of indemnification coverage for these assets in the event of a loss due to an extraordinary retirement should lie with their owner, the utility. The utility may not recover these costs from customers because doing so would effectively provide the utility and its shareholders with asymmetrical access to the benefits, but not the attendant risks, of asset ownership. Granting ATCO Electric's request would effectively convert the utility's opportunity to recover prudently incurred costs in the event of extraordinary retirement into a certainty at customer expense. The Commission finds that such a situation is not contemplated by the regulatory compact in Alberta as interpreted and applied by the courts.

14.2 Reserve for injuries and damages

1267. ATCO Electric sought Commission approval to annually settle any differences for 2015 and future years between the approved and actual amounts within the account RID as part of the transmission deferral account and annual filing for adjustment balances application.

[916] Decision 2191-D01-2015: 2013 Generic Cost of Capital, March 23, 2015 at paragraphs 346 and 351.

1268. Based on a five-year average, ATCO Electric's forecast for each of the three test years was $700,000.

Commission findings

1269. There were no objections by interveners to ATCO Electric's forecast or its request to settle differences on an annual basis.

1270. The Commission accepts and approves ATCO Electric's forecast amount and its proposal to settle the account annually. The Commission confirms that the eligibility of future casualties for RID treatment will be determined in accordance with the principles described in the Slave Lake decision.

14.3 Second prior year actual for corporate cost allocation factor

1271. In its application, ATCO Electric proposed to forecast head office costs for recovery during the test period using each year's second prior year actual amounts to derive the allocation factors.[917]

1272. ATCO Electric further explained that it was "applying to recover its head office costs using updated allocation percentages, compared to those approved by the AUC in ATCO Electric's 2013-2014 GTA." However, it did not propose to use the same allocation approach in each of 2015, 2016 and 2017. Instead, it confirmed that it had used second prior year (2013) *actuals* as an allocating factor for 2015, consistent with the method previously approved by the Commission. For 2016, however, ATCO Electric is using its 2014 *forecast* which will be updated when 2014 actuals become available. Likewise, for 2017, ATCO Electric is using its 2015 *forecast* which it proposes to update, when actuals become available, in a compliance filing in 2016.[918]

Commission findings

1273. There were no comments by interveners in respect of the proposed allocation method. However, the Commission has reviewed the method approved in ATCO Electric's 2013-2014 GTA and draws attention to the following determinations made in that decision and Decision 2013-111:[919]

> 134. The time frame from which to obtain the input figures used in the allocation methodology was not an issue for the UCA during this proceeding. In the current methodology employed by ATCO Ltd., the inputs are obtained from audited financial statements from two years prior. When asked to comment on this, Mr. Bell indicated that he was not opposed to the continuation of this two-year lag. **The Commission considers that the continued use of data from the audited financial statements from two years prior is reasonable.** The use of actual audited data prevents any forecasting errors with respect to the inputs to be used, and provides a reliable data source. **Therefore, the Commission finds that the current practice with respect to the use of data from two previous years should continue.**[920] **[**emphasis added]

[917] Exhibit 20272-X0002 ATCO Electric 2015-2017 GTA Section 1 to 30, PDF page 16.
[918] Exhibit 20272-X0002 ATCO Electric 2015-2017 GTA Section 1 to 30, PDF pages 22-23.
[919] Decision 2013-111: The ATCO Utilities, Corporate Costs, Proceeding 1920, Application 1608510-1, March 21, 2013.
[920] Decision 2013-111, paragraph 134.

And

> 131. In Decision 2013-111, the Commission approved the methodology to be used to allocate the total forecast corporate costs for 2012 and for subsequent years. This approved methodology causally allocates the costs for the internal audit function and the human resources function, and uses a formula to allocate the remaining costs. This formula consists of an equal weighting to be given to the following: labour expense, total assets, and revenue net of commodity charges, items that flow through to utility customers, and any items eliminated on consolidation from the allocation methodology calculations. **In Decision 2013-293, the Commission approved the use of audited financial data from two years prior to the test year as inputs into the allocation formula. [**emphasis added]
>
> 884. ….The Commission directs that the use of the 2011 actuals as inputs in the calculation of the revised methodology is applicable, **because these represent information from two years prior to the first test period.** The Commission commented on this in paragraph 134 of Decision 2013-111. [emphasis added]
>
> 954. Attachment 1, Schedule 2(a) to the response to information request CCA-AE-45(a) shows that the credit facility costs were allocated to the various CU Inc. and Canadian Utilities Limited subsidiaries using the cost allocation methodology that is based on the average of revenues, assets, and capital expenditures. In Decision 2013-111, the Commission directed that there should be changes to the allocation methodology used to allocate the ATCO Ltd. corporate costs. **The Commission considers that, for consistency and for the same reasons it directed the changes to the allocation methodology in Decision 2013-111, the same changes should be made to the revenues, assets and capital expenditures methodology used to allocate the cost of the credit facilities. The Commission directs that the 2011 actuals should be used as inputs in the calculation of the revised methodology, as these represent information from two years prior to the first test period.** The Commission commented on this in paragraph 134 of Decision 2013-111.[921] [emphasis added]

1274. As the above excerpts from Decision 2013-358 make clear, the Commission directed that, in the interests of consistency, data reliability and avoiding forecasting errors, allocations of head office costs were to be based on the actual audited financial data from two years prior to the first test year.

1275. Although ATCO Electric has acknowledged that its proposal deviates from the methodology approved in Decision 2013-358, it has provided no reasons to justify it. ATCO Electric did not describe any benefits of its proposal nor demonstrate why it is reasonable. It likewise provided no comparison of results that would flow from its preferred approach relative to the approved method. For these reasons, the Commission declines to approve the method proposed and directs ATCO Electric to use the audited financial data from 2013 to determine the allocation factors for all three test years.

14.4 IT volumes and placeholder costs

1276. ATCO Electric provided the following definition of IT operating costs:

> IT services charged to Operating Costs include costs to operate, maintain and distribute existing and new IT applications required by AET to manage its financial, human

[921] Decision 2013-358, paragraphs 131, 884 and 954.

> resources and operational activities (e.g. Oracle, Maximo). These services also include charges for the provision of hardware (e.g. PCs, laptops, monitors); network, voice (telecommunications), data storage and printing management and infrastructure; and ad hoc service requests.[922]

1277. ATCO Electric stated that it had changed its IT service provider to Wipro in 2014. It claimed that the rates charged by Wipro were lower, on average, than those charged by its previous service provider, ATCO I-Tek. ATCO Electric forecast that its IT volumes would increase in the test period due to the combined effects of a forecast increase in FTEs and additional applications. Operating costs in the test period were forecast to be $8 million, $9 million and $9.8 million for 2015, 2016, and 2017, respectively.[923]

1278. ATCO Electric explained that the forecast increases in operating costs were due to system enhancements and associated higher costs for software. The forecast software costs were related to applications for finance, safety reporting and human resources management, other software including Sharepoint, and increased application support services for general property and equipment (GP&E) software projects. ATCO Electric stated that "[t]hese software enhancements are required to support ATCO Electric's growing work force as a result of transmission system growth, to improve efficiency, and to deal with the loss of knowledge and experience due to staff retirements and turnover."[924]

1279. In its argument, ATCO Electric stressed that matters related to IT volumes were to be tested in this proceeding, while matters related to pricing of IT services would be considered in the ATCO Utilities IT Common Matters (Proceeding 20514), which was initiated on June 4, 2015.

1280. ATCO Electric submitted that its forecast volumes were reasonable and had been adjusted to account for reductions in its workforce that occurred at the end of November 2015.

1281. Calgary filed argument on a variety of IT-related matters including IT O&M and capital expenditures, FTEs, business cases and the use of offshoring in procuring IT services.[925] However, in doing so, it indicated that "[i]n this Proceeding, Calgary is testing IT volumes only. Calgary understands that cost amounts will remain as placeholders pending testing of the prices in the Wipro MSAs [master service agreements] in Proceeding ID 20514."[926]

1282. ATCO Electric submitted in its reply that Calgary's argument primarily dealt with pricing matters and not volumes. It also reiterated that it had made adjustments due to workforce reductions and that the matter was addressed in Exhibit 20272-X0758 (page 58).[927]

Commission findings

1283. The Commission confirms that its IT-related inquiries in the current application are restricted to an assessment of the reasonableness of the forecast volumes provided by ATCO

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[922] Exhibit 20272-X1100, Attachment 1 – Revised Application Narrative – Clean, paragraph 497, PDF page 376.
[923] Exhibit 20272-X1100, Attachment 1 – Revised Application Narrative – Clean, paragraph 498, PDF pages 376-377.
[924] Exhibit 20272-X1100, Attachment 1 – Revised Application Narrative – Clean, paragraph 499, PDF page 377.
[925] Exhibit 20272-X1299, Calgary redacted argument, PDF pages 35-39.
[926] Exhibit 20272-X1299, Calgary redacted argument, paragraph 110, PDF page 34.
[927] Exhibit 20272-X0758, ATCO Electric information responses to CCA-001 to 019, AET-CCA-2015DEC30-009, PDF page 58.

Electric for the test period. The reasonableness of forecast IT costs over the term of the applicable master service agreements will be assessed in the Commission's IT Common Matters proceeding (Proceeding 20514).

1284. The Commission observes that in Exhibit 20272-X0758 ATCO Electric provided a response to an IR by setting out dollar amounts. The Commission directs ATCO Electric to provide, in the compliance filing, the volume amounts that were used to calculate the dollar values, an explanation of which category of volumes was adjusted, and the final volume amount for each test year. ATCO Electric is also directed to provide an update to Exhibit 20272-X0721, AET-CAL-2015DEC30-004(h) Attachment 1, and Exhibit 20272-X0722, AET-CAL-2015DEC30-006(a) Attachment 1 if required to comply with the above directive.

1285. The Commission is of the view that the determination of pricing, which is the subject of proceeding 20514, will be necessary to finalize costs related to O&M, capital, FTEs and the use of offshoring. Accordingly, since there are no specific recommendations to adjust the volumes as filed, the Commission will accept ATCO Electric volumes as forecast and as subsequently adjusted for workforce reductions, subject to a review of the final volumes submitted in the compliance filing as directed.

15 Financing and credit metrics

15.1 Credit metrics

1286. ATCO Electric requested approval for continuation of credit relief measures including recovery of transmission direct assigned CWIP in rate base, recovery of federal future income taxes (FIT), and recovery of the capital portion of pension costs on a cash basis, previously granted in Decision 2013-358.[928]

1287. In ATCO Electric's 2011-2012 GTA, the Commission had granted approval to the utility for recovery of its transmission FIT through 2011 and 2012. ATCO Electric was also permitted to include its transmission direct assigned CWIP in rate base to address the potential for negative impacts on its credit metrics arising from the level of its capital program and the significant amount of CWIP forecast for 2011 and 2012. These credit relief measures were intended to be temporary in nature, with the continued need for them being re-evaluated going forward.[929]

1288. ATCO Electric explained that in the current test period it was forecasting a moderation of the record capital program experienced in 2011-2014.[930] However, it also noted that in July 2015, Standard & Poor's (S&P) changed the ratings outlook of ATCO Ltd. and its subsidiaries, CU Inc. and Canadian Utilities Limited. to negative from stable.[931] In its report, S&P further noted that if the funds from operation (FFO)-to-debt ratio falls to, or below, 14 per cent on a consistent basis a downgrade would be issued.

1289. S&P's reasons, as summarized by ATCO Electric,[932] included the following:

[928] Exhibit 20272-X1100, application, paragraph 524, PDF pages 381.
[929] Exhibit 20272-X1100, application, paragraph 522, PDF page 380.
[930] Exhibit 20272-X1100, application, paragraph 523, PDF page 380.
[931] Exhibit 20272-X0583, S&P's research update.
[932] Exhibit 20272-X1100, application, paragraph 524, PDF pages 380-381.

> … "the company's forecast financial metrics in the context of a more difficult Alberta operating environment, as well as its aggressive capital program, weaken the rationale for our positive comparable rating modifier on the company. Recent regulatory decisions also put additional pressure on the company's revenue and cash flow," specifically "the generic cost of capital decision, in which equity thickness and return on equity were lowered by 100 basis points (bps) and 45 bps, respectively, and retroactively applied to previous years in 2013 and 2014; as well as the utility asset disposition ruling that equity investors need to bear the risk of stranded assets instead of ratepayers." S&P further noted that if the AFFO-to-debt ratio falls to, or below 14% on a consistent basis then a downgrade would be issued, while S&P could "revise the outlook back to stable should the company manage the capital program through the current operating environment with AFFO-to-debt returning to about 18% or better on a sustained basis…."

1290. ATCO Electric proposed an FFO/debt ratio of at least 14 per cent. It noted that this level would fall within the 14-18 per cent range described in S&P's analysis as being supportive of an "A stable" rating. ATCO Electric also cited DBRS as describing stable cash flow to debt levels as being in the range of 15 per cent.

1291. ATCO Electric stated that its parent, CU Inc., currently maintains an "A- rating" from S&P and an "A(high)-Stable" rating from DBRS.

1292. In the updated application, ATCO Electric financially modelled five scenarios with respect to its requested credit metrics relief, as summarized in the table below. These included: (1) keeping CWIP in rate base as well as collecting federal future income taxes and the capital portion of pension costs; (2) removing the collection of the capital portion of pension costs from the currently approved credit relief; (3) maintaining CWIP in rate base as the sole measure of credit relief; (4) retaining federal FIT as the sole measure of credit relief; and (5) denying all credit relief.

Table 59. Credit metric scenarios

2015	Scenarios				
	DA CWIP in rate base & FIT & capitalized pension (1)	CWIP in rate base & FIT (2)	CWIP in rate base (3)	Federal FIT (4)	No relief (5)
FFO / debt	12.6%	12.4%	11.5%	10.4%	9.5%
FFO interest coverage	3.69	3.64	3.46	3.22	3.04
Interest coverage	2.23	2.23	2.00	1.73	1.50

2016	Scenarios				
	DA CWIP in rate base & FIT & capitalized pension (1)	CWIP in rate base & FIT (2)	CWIP in rate base (3)	Federal FIT (4)	No relief (5)
FFO / debt	14.2%	14.1%	13.6%	13.8%	13.3%
FFO interest coverage	4.06	4.02	3.93	3.95	3.86
Interest coverage	2.33	2.33	2.21	2.25	2.13

2017	Scenarios				
	DA CWIP in rate base & FIT & capitalized pension (1)	CWIP in rate base & FIT (2)	CWIP in rate base (3)	Federal FIT (4)	No relief (5)
FFO / debt	14.4%	14.2%	13.9%	13.8%	13.5%
FFO interest coverage	4.05	4.02	3.95	3.93	3.87
Interest coverage	2.35	2.35	2.26	2.25	2.17

Source: Based on Exhibit 20272-X1100, application, Table 28.1 Credit Metric Scenarios, paragraph 530, PDF pages 383-384.

1293. ATCO Electric explained that the above credit metrics were calculated using a placeholder ROE of 8.30 per cent and an equity ratio of 36 per cent. Further, the key credit metric of FFO/debt depends on other items in the application, such as depreciation expense. Consequently, the utility clarified that if the full amount of depreciation expense it had requested was not approved by the Commission, then consideration would need to be given to the appropriate level of credit relief to be awarded for 2015, 2016 and 2017.[933]

1294. Decision 2191-D01-2015, regarding the 2013 Generic Cost of Capital for Alberta utilities, including ATCO Electric, determined that the following minimum credit metrics were consistent with regulated utilities being able to target an A-range credit rating:[934]

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

1295. The CCA stated that ATCO Electric's request to augment its credit metrics based on the S&P research update it provided, which referenced the generic cost of capital and the UAD

[933] Exhibit 20272-X1100, application, paragraph 532, PDF pages 384-385.
[934] Decision 2191-D01-2015, paragraph 426.

decisions, should not be accepted.[935] It argued that while continued use of the federal FIT method provides the means to optimize key financial ratios such as FFO to debt, and could help to address intergenerational equity concerns, including CWIP in rate base and allowing recovery of the capitalized portion of pension costs were temporary credit relief measures introduced to maintain reasonable cash flows during surges in transmission construction. It claimed that these supports were no longer required.

1296. The UCA took a similar position. It submitted that pension plan funding, recovery of federal FIT, and transmission direct assigned CWIP in rate base were intended to be temporary. It argued that for 2016 and 2017 no temporary relief is required because there is no large capital build, and only some relief may be needed for 2015. In its view, if any relief is found to be necessary it should be the lowest cost option in terms of its impact on customers. According to the UCA, this is likely to be FIT because it provides no cost capital, which offsets the return on rate base otherwise earned.[936]

1297. The UCA argued that the S&P ratings report, which revised its outlook for the ATCO Group to negative due in part to capital programs (such as the West Fort McMurray Transmission project) planned by its unregulated subsidiaries, could put pressure on the group's financial metrics. However, these projects were not the responsibility of ATCO Electric.[937] The UCA further argued that if circumstances have changed such that ATCO Electric requires credit metrics different from those determined in the 2013 GCOC proceeding to target an "A range" credit rating, then that issue should be considered in the pending GCOC proceeding where credit metrics are established for all Alberta utilities.[938]

1298. The RPG stated that credit metrics levels are thresholds only. It also argued that the financial risk profiles of ATCO Ltd. and CU Inc., the only ATCO group companies actually rated by S&P, are considerably higher than that for a low volatility cash flow utility such as ATCO Electric. Consequently, in its view, the Commission should assess ATCO Electric's credit metrics on a standalone basis as a low risk TFO to avoid the possibility of its metrics being used to prop up the credit ratings of ATCO Ltd. and its subsidiaries, CU Inc. and Canadian Utilities Limited.[939]

1299. The RPG submitted that an 11 per cent FFO/debt ratio was appropriate for ATCO Electric for two reasons: (1) it represented the mid-point of the nine to 13 per cent range S&P considers sufficient to support low volatility cash flow companies with a significant financial risk profile; and (2) 11 per cent is within the range previously approved by the Commission.[940] It argued that ATCO Electric could achieve an 11 per cent FFO/debt ratio by retaining CWIP in rate base for 2015, and that no credit metric support was required for either of 2016 or 2017.[941] The RPG claimed that the federal FIT method was not necessarily a temporary credit relief measure and submitted that it should be maintained throughout the test period. It characterized

[935] Exhibit 20272-X0785, CCA evidence prepared by Raj Retnanandan, paragraphs 97 and 113-115, PDF pages 31 and 36-37.
[936] Exhibit 20272-X0777, UCA evidence prepared by Russ Bell, paragraphs A9, PDF pages 5-6.
[937] Exhibit 20272-X0777, UCA evidence prepared by Russ Bell, paragraphs A10, PDF pages 6-7.
[938] Exhibit 20272-X0777, UCA evidence prepared by Russ Bell, paragraphs A10, PDF pages 7-8.
[939] Exhibit 20272-X0783, RPG evidence prepared by Ron Mikkelsen, paragraphs A23, PDF pages 11.
[940] Exhibit 20272-X0783, RPG evidence prepared by Ron Mikkelsen, paragraphs A 27 and A29, PDF pages 12 and 14.
[941] Exhibit 20272-X0783, RPG evidence prepared by Ron Mikkelsen, paragraphs A32, PDF page 15.

both CWIP in rate base and capitalized pension as temporary credit relief measures that should be discontinued.

1300. The RPG recommended the following credit metric support in the event that ATCO Electric's depreciation proposals were rejected by the Commission. It claimed that an FFO/debt ratio of 11 per cent could be maintained in 2015 by continuing to include CWIP in rate base, continuing federal FIT and capitalized pension expense, and increasing ATCO Electric's deemed equity level to 36.5 per cent. The RPG claimed that the same result might also be obtained in 2016 by continuing to apply CWIP in rate base, federal FIT and a capitalized pension expense. It submitted that for 2017, only the CWIP and federal FIT supports would be required.[942]

1301. The RPG recommended that ATCO Electric be directed to update its filing for all final approved depreciation parameters and to provide the revised credit metrics in its compliance filing.

1302. In argument, ATCO Electric relied upon the stand alone principle, and submitted that each utility was required to contribute its "fair share" to the maintenance of CU Inc.'s (CUI) overall corporate credit position. It argued that it was in its own interests to support the credit ratings of Canadian Utilities Limited (CUL) and its subsidiaries because this affiliation allowed it access to capital at a lower cost.[943]

Commission findings

1303. In response to correspondence from ATCO Electric, the Commission explained that it "will consider the necessity of continuing to provide credit metric relief to AET [ATCO Electric] as part of the determination of the company's 2015-2017 GTA. If continuation of relief is found to be required, the Commission will also determine what form such relief should take. The Commission confirms that the GTA inquiry is not intended to establish the company's deemed capital structure for the test period."[944]

1304. The Commission observes that ATCO Electric has based its credit metric requirements on the comments and expectations of S&P's group-based credit rating methodology, and used this in support of its submission that it must be positioned to "contribute its fair share" to the maintenance of the rating currently enjoyed by CUL and its subsidiaries, including CU Inc. ATCO Electric has also emphasized that its requests should be assessed on the basis of the "stand alone principle." In other words, its operations and financial health should be considered as though it conducted its business in isolation from the ATCO Group. The suggestion is that the level of credit metric support provided to ATCO Electric should enable it to support an "A stable" credit rating and not be lessened in an attempt to account for the fact that it is associated with a larger group of companies.

1305. The Commission agrees that the adequacy of ATCO Electric's credit metrics, and the necessity of any required support, should be assessed on a stand-alone basis. Consequently, to determine their reasonableness, the Commission has considered whether, and to what extent, ATCO Electric's forecast credit metrics conform to the ranges and minimums prescribed in the 2013 GCOC decision. The Commission is not persuaded that an assessment of what might

[942] Exhibit 20272-X0783, RPG evidence prepared by Ron Mikkelsen, paragraphs A33, PDF pages 15-16.
[943] Exhibit 20272-X1298, ATCO Electric argument, paragraph 354, PDF pages 130-131.
[944] Exhibit 20272-X0801, Commission correspondence, paragraph 4, PDF page 1.

constitute ATCO Electric's "fair" contribution to the credit metrics of other companies in the ATCO Group, including CUL and CU Inc., is relevant to its inquiry in this regard.

1306. The Commission notes that most interested parties focused their respective discussions regarding credit metrics on the FFO/debt ratio. In Decision 2191-D01-2015, the Commission confirmed its view that maintaining an FFO/debt ratio in the range of 11.1 to 14.3 per cent was consistent with targeting a credit rating in the "A range." The Commission's view in this regard has not changed. The current proceeding applies to the 2015, 2016 and 2017 test years. The 2015 test year has come and gone without any of CUL, ATCO Ltd. or CU Inc. having experienced a credit rating downgrade. Two-thirds of 2016 have now passed with ATCO Electric forecast to maintain an FFO/debt ratio well within the range prescribed in the 2013 GCOC, and without any evidence of a downgrade to the credit ratings of either CUL, ATCO Ltd. or CU Inc.

1307. On the basis of the foregoing, the Commission concludes that the FFO/debt ratio is an important, if not the most important, metric that is evaluated in the assessment of a regulated utility's creditworthiness. It also finds that there is nothing to suggest that ATCO Electric's recent historical FFO/debt levels, as supported by existing measures, have resulted in either CUL, ATCO Ltd. or CU Inc. credit assessments being revised downward. The Commission has determined that ATCO Electric may continue to include recovery of transmission direct assigned CWIP in rate base, recovery of federal FIT, and recovery of the capital portion of pension costs on a cash basis for 2015 and 2016.

1308. The Commission considers, however, that the continuation of all these measures throughout 2017 is not warranted. Its conclusion in this regard is based on an assessment of forecast levels of capital program activity and their resulting impacts on the utility's cash flow, as projected in the scenarios provided by ATCO Electric. The Commission finds that, as suggested by these scenarios, the withdrawal of CWIP in rate base, and recovery of the capital portion of pension costs on a cash basis will result in ATCO Electric continuing to maintain a stand-alone FFO/debt ratio sufficient to maintain its creditworthiness at current levels. Further, and in any event, the Commission considers that it is able to address any impacts that may arise from the combined effect of the withdrawal of these measures and other directions in this decision in its assessment of ATCO Electric's deemed capital structure in the pending 2016 GCOC proceeding. Overall, the Commission considers that disallowing both CWIP in rate base and the recovery of the capital portion of pension costs on a cash basis in 2017 will result in a lower transmission tariff, while maintaining key credit metric levels required to permit ATCO Electric to target credit ratings in the "A range."

1309. The Commission notes that the CCA supported continuation of the use of federal FIT as a credit relief measure to optimize financial ratios such as FFO/debt and also as a means of addressing intergenerational concerns, whereas the UCA supported its use as a least cost form of credit relief due to the related no cost capital which offsets a portion of the return on rate base. The RPG also supported continuation of the federal FIT method throughout the test period. The Commission considers that continuation of the federal FIT method will serve to support the FFO/debt level and a stable credit rating in light of determinations in Section 8 of this decision on depreciation expense. For the above reasons, the Commission approves ATCO Electric's use of the federal FIT method for the 2017 test year.

1310. ATCO Electric is directed, starting January 1, 2017, to (1) resume normal regulatory AFUDC accounting for direct assigned capital, (2) discontinue CWIP in rate base for direct assigned projects, and (3) discontinue recovering the capital portion of pension costs on a cash

basis, and instead return to collection of the capital portion of pension expense as part of invested capital. ATCO Electric is directed to reflect this in the compliance filing.

1311. ATCO Electric is further directed to propose a method, in the compliance filing to refund the accumulated difference resulting from the change in accounting treatment of capital pension costs, including related income tax impacts. Supporting schedules shall be provided for calculations of all adjustment amounts proposed, along with identification of all assumptions made.

1312. The Commission has made its determinations on the level of depreciation expenses in Section 8 of this decision. Determinations made in other sections of this decision may also have impacts on the calculation of credit metrics. The Commission directs ATCO Electric, in the compliance filing, to reflect all findings and determinations included in this decision which affect the credit metrics measures. ATCO Electric is directed to provide updated credit metric ratios by year as displayed in Table 59 above.

15.2 Cost of debt

1313. ATCO Electric and its sister company, ATCO Gas and Pipelines Ltd. (operating as ATCO Gas and ATCO Pipelines) obtain external financing through their direct parent CU Inc.

1314. In ATCO Electric's original application, it forecast the following long-term debt issues and terms:

Table 60. Summary of original forecast long-term debt issues during test period

Issue	Rate	Amount ($ million)	Maturity
2015	4.00%	283	2045
2016	4.65%	130	2046
2017	5.30%	304	2047

Source: Based on Exhibit 20272-X1100, application, Table 28.3 Long-Term Debt Issues During Test Period, paragraph 536, PDF page 737.

1315. In Decision 2013-358, relating to the utility's 2013-2014 GTA, the Commission established a deferral account for debt cost rates. In the current application, ATCO Electric proposed that use of this deferral account be continued during the test period.

1316. Over the course of the proceeding, ATCO Electric's actual long-term debt financing requirements for July and October 2015 were approved in Decision 20867-D01-2105[945] and Decision 20999-D01-2015,[946] respectively. The following amounts were issued in 2015:

[945] Decision 20867-D01-2015: ATCO Electric Ltd., Issuance of 3.964 Per Cent Debenture, Proceeding 20867, November 2, 2015.
[946] Decision 20999-D01-2015: ATCO Electric Ltd., Issuance of 4.211 Per Cent Debenture, Proceeding 20999, December 10, 2015.

Table 61. Actual 2015 debt financing

Issue	Rate	Amount ($ million)	Maturity
July 27, 2015	3.964%	$110	2045
October 29, 2015	4.211%	$185	2055

Source: Based on Exhibit 20272-X1100, application, Table 28.2 AUC Approved Long Term Debt Issues, paragraph 535, PDF page 386, updated for Exhibit 20272-X0620, October 30, 2015 application update for 2015 actual debt financing, information response AET-AUC-2015OCT16-024 (b), PDF page 83.

1317. In its rebuttal evidence dated February 23, 2016, ATCO Electric forecast the following updated long-term debt requirements and rates for the balance of 2016 and 2017:

Table 62. Current debenture rate forecasts for 2016 and 2017

	2016	2017
Long Canada bond rate	1.90 – 2.70	2.30 – 3.30
Credit spread	1.80 – 2.20	1.80 – 2.20
Debenture rate	4.30	4.80

Source: Based on Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 9.

1318. However, in its updated application and Schedule 28-2[947] showing debt capital forecasts by issue, also dated February 23, 2016, ATCO Electric forecast the issuance of long-term debt for the remaining test years with different and higher interest rates:

Table 63. Forecast long-term debt issues during test period

Issue	Rate	Amount ($ million)	Maturity
2016	4.70%	$120	2046
2017	5.45%	$55	2047

Source: Based on Exhibit 20272-X1100, application, Table 28.3 Long-Term Debt Issues during Test Period, paragraph 547, PDF page 386.

1319. With regard to debt cost rate forecasts, the CCA argued that consensus forecasts, used for the GCOC, should be used instead of the bank forecasts relied upon by ATCO Electric for the purpose of forecasting debt cost rates because debt cost forecasts are otherwise overstated.[948]

1320. The CCA further submitted that ATCO Electric had continually changed its methodology for determining credit spreads. It noted that the utility used observed credit spreads going back to 2011 to arrive at the 150 basis point midpoint used in its initial application. However, its October 2015 application update used a range of 170-190 with a midpoint of 180, based on indicative spreads rather than specific issues. Finally, in its rebuttal evidence, ATCO Electric widened the spreads further to 180-220.[949]

1321. At the oral hearing, the CCA's witnesses stated that credit spreads had dropped to levels below what ATCO Electric had used in its October 2015 update. They submitted that the March 28, 2016 spread was 1.73 per cent and the spread as of May 5, 2016 was 1.55 per cent and falling, which is just above the 150 points used by ATCO Electric in its original application.

[947] Exhibit 20272-X1101, Schedule 28-2 Schedule of Debt Capital Employed and Embedded Cost.
[948] Exhibit 20272-X0775, CCA evidence prepared by Jan Thygesen, paragraphs 36-37, PDF page 16.
[949] Exhibit 20272-X1294, CCA argument prepared by Jan Thygesen, paragraphs 3-8, PDF pages 3-6.

Consequently, the CCA recommended using the original application forecast credit spread of 150 basis points.[950]

1322. CCA submitted that while consensus forecasts have consistently over-forecast rates, the bank forecasts used by ATCO Electric are even higher. The CCA provided information on the use of the Bloomberg forward curve rate and submitted that it had a potential use in forecasting long-term debt rates more accurately.

1323. For example, for the 2016 test year, the CCA recommended using the average of the forward curve rate of 3.62 per cent and the consensus forecast rate of 3.44 per cent to arrive at an overall forecast rate of 3.53 per cent. For 2017, the CCA recommended using a weighted average of two-thirds forward curve rate and one-third consensus forecast to determine a rate of 3.78 per cent.[951]

1324. ATCO Electric explained that its practice is to consider economic forecasts from capital market advisors at banks that assist CU Inc. in executing its long-term debt financings, as well as the *Consensus Forecast*, to determine a reasonable range for the long Government of Canada bond yield forecast. ATCO Electric submitted that this approach allows it to incorporate the best information available in its debt rate forecasts.[952]

1325. ATCO Electric also argued that credit spreads have increased significantly since it submitted its O&U filing on October 2, 2015, with the indicative credit spread for new 30-year CU Inc. debentures at January 25, 2016 being 210 basis points while the actual credit spread realized for a CU Inc. October 2015 debenture issue was 198 basis points owing to market volatility.[953]

1326. ATCO Electric stated that a debenture rate is made up of an underlying Government of Canada (GOC) bond yield and a credit spread and argued that, while it may be possible to hedge an underlying GOC bond yield for a period of time (typically up to a year into the future through a bond forward contract) it is not possible to hedge credit spreads.[954]

1327. In support of its request to keep the deferral account treatment for the cost of new debt, ATCO Electric stated that the deferral account was required since debt rates are still volatile, as shown by the downward revisions in forecast debt rates in the current proceeding.[955]

Commission findings

1328. The Commission's predecessor, the Alberta Energy and Utilities Board, found that it did "not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice [has] been to evaluate the use of a deferral account on a case-by-case basis, on its own merit."[956]

[950] Exhibit 20272-X1294, CCA argument prepared by Jan Thygesen, paragraphs 9-10, PDF pages 6-7.
[951] Exhibit 20272-X1294, CCA argument prepared by Jan Thygesen, paragraphs 29-34, PDF page 13.
[952] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 10.
[953] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 9.
[954] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 9.
[955] Exhibit 20272-X1298, ATCO Electric argument, paragraph 370, PDF pages 142 and 143.
[956] Decision 2003-100: ATCO Pipelines 2003/2004 General Rate Application – Phase I Application 1292783-1, December 2, 2003, page 116.

1329. In Decision 2010-189,[957] the Commission considered the following criteria when evaluating the need for a deferral account:[958]

- materiality of the forecast amounts
- uncertainty regarding the accuracy and ability to forecast the amounts
- whether or not the factors affecting the forecasts are beyond a utility's control, and
- whether or not the utility is typically at risk with respect to the forecast amounts

1330. In addition, the Commission has also considered a symmetry factor,[959] as described below:

> 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. [footnotes omitted]

1331. The Commission notes that none of the parties objected to the continued use of a deferral account for debt cost rates, and that the concerns expressed by the CCA related to the forecast cost of debt for the test years.

1332. The Commission considers forecasting debt cost rates involves reliance on credit spread predictions that continue to display volatility, historically ranging from 150 to 220 basis points. Debt cost rates forecast at the beginning of the current proceeding to be 4.0 per cent, 4.65 per cent and 5.3 per cent for each of 2015, 2016 and 2017, respectively, have subsequently been replaced by actual rates for 2015 of approximately 4.0-4.2 per cent, and forecasts of 4.3 per cent and 4.8 per cent for 2016 and 2017, respectively.

1333. Cumulative debt offerings being forecast for the test period involve amounts approaching $0.5 billion. Given the magnitude of the amounts involved, the Commission considers that nominally small changes in debt cost rates can result in material impacts on revenue requirement. The Commission notes that without the use of a deferral account, the utility or the ratepayer are at risk for differences in debt costs. ATCO Electric does not have control over general interest rates or the credit spreads required by the market. As previously noted, the forecast rate of 4.0 per cent for 2015 was, in fact, lower than the actual debt cost rate for the October 2015 issue at 4.2 per cent, but the rates forecast for 2016 and 2017 have been reduced over the course of the proceeding. As required by the symmetry factor, the Commission considers that the continued use of deferral account treatment will provide a balance of protection for the utility and customers.

[957] Decision 2010-189: ATCO Utilities, Pension Common Matters, Proceeding 226, Application 1605254-1, April 30, 2010.
[958] Decision 2010-189, paragraph 72.
[959] Decision 2010-189, paragraph 73.

1334. The Commission considers that a deferral account for debt cost rates should only be used for 2016 and 2017. The Commission directs that actual debt cost rates be used for 2015.

1335. The calculation of the annual debt cost rate deferral is to be determined by updating the approved "Schedule of Debt Capital Employed and Embedded Cost" (Schedule 28-2) for 2016 to reflect the actual weighted debenture rate for 2015; and updating the same schedule for 2016 to reflect the actual weighted debenture rates for each of 2015 and 2016. The rate for 2017 will similarly be updated to reflect the actual weighted debenture rates for each of 2015, 2016 and 2017. The resulting embedded cost of debt for the applicable year will then be used to update the "Schedule of Capital Structure and Average Cost of Capital" (Schedule 28-1) for that year. This will result in an updated return on long-term debt for that year. The difference between the updated return on debt and the approved return on debt for that year will be the resulting balance in the debenture rate deferral account for that year.

1336. Having approved the use of a deferral account for debt costs over the last two years of the test period, the Commission is also required to determine a reasonable forecast for the cost of debt in each of the test years. The actual cost of debt for ATCO Electric's 2015 debt issuances is known. For this reason, the Commission directs ATCO Electric, in the compliance filing, to update its application in all aspects to reflect the 2015 actual cost of debt resulting from the actual 2015 long-term debt issues. The Commission finds that, overall, the forecasting method employed by ATCO Electric in respect of 2016 and 2017 debt cost rates is reasonable. On balance, it is not persuaded that the adoption of the methodology proposed by the CCA, which incorporates weighted averages of both consensus forecast and Bloomberg forward curve data, will result in a significant reduction of forecast risk, especially since this cost will be afforded deferral account treatment.

1337. The Commission notes that ATCO Electric provided conflicting debt cost rate forecasts for 2016 and 2017 based on information it filed on the same day. The Commission approves ATCO Electric's forecast debt cost rates of 4.3 per cent and 4.8 per cent for each of 2016 and 2017, respectively. The Commission considers these cost rates to be reasonable based on a comparison to the recent actual experience for 2015 being in the 4.0 per cent to 4.2 per cent debt cost range and, based on its approval of deferral account treatment for use in each of 2016 and 2017. The Commission directs ATCO Electric, in the compliance filing, to update its application in all aspects to reflect the forecast long-term debt cost rates of 4.3 per cent and 4.8 per cent for 2016 and 2017, respectively.

16 Affiliate transactions

16.1 Alberta Powerline

1338. In the application, ATCO Electric forecast the provision of affiliate services to Alberta PowerLine LP. (Alberta PowerLine), in support of the West Fort McMurray 500-kV AC Transmission Project (WFMAC) during the test period. ATCO Electric submitted that these services will be provided in accordance with the ATCO Group Inter-Affiliate Code of Conduct (Code). ATCO Electric described the WFMAC and the nature of the services it will provide as follows:[960]

[960] Exhibit 20272-X1100, application, paragraph 33, PDF page 18.

33. Alberta PowerLine (APL), a partnership between ATCO and Quanta Services, was selected by the Alberta Electric System Operator (AESO) to design, build, own, operate and finance the Fort McMurray West 500-kilovolt (kV) Transmission Project. Alberta PowerLine is 80% owned by Canadian Utilities Limited, an ATCO company, and 20% owned by Quanta Services. Valued at $1.43 billion, the project was awarded through Alberta's recently instituted competitive process. Under the partnership, Valard Construction, a Canadian subsidiary of Quanta, will provide turnkey EPC services for the project while AET will be responsible for route planning and operations and maintenance of the transmission facilities for 35 years, as well as providing management services to APL. Alberta PowerLine submitted its Facilities Application to the AUC in 2015. If approved, construction of the transmission line is scheduled to start in 2017 and be in service in 2019.

1339. A summary of the services forecast to be provided by ATCO Electric, in both costs and FTEs, is provided in the following tables:

Table 64. Summary of forecast affiliate services for WFMAC project

GTA category / reference	2015 test period	2016 test period	2017 test period
	($ million)		
Transmission			
Labour	2.24	4.25	4.70
Fringe	0.45	0.85	0.94
Overhead	1.57	2.97	3.29
(B) Schedule 5-3 USA 566 line 17	**4.26**	**8.07**	**8.93**
Corporate			
Labour	0.45	1.19	1.36
Fringe	0.09	0.24	0.27
Overhead	0.32	0.83	0.95
(A) Schedule 25-3 USA 930.2 line 36	**0.86**	**2.27**	**2.58**
Total Corporate and Transmission (A) + (B)	**5.12**	**10.34**	**11.51**
Revenue offset Schedule 8-1 line 5	**(5.12)**	**(10.34)**	**(11.51)**
Revenue requirement impact	-	-	-

Source: Based on Exhibit 20272-X1100, application, Table 1.4 Summary of WFMAC Affiliate Services, paragraph 34, PDF page 19.

Table 65. Summary of forecast affiliate services for WFMAC project in FTEs

GTA category / reference	2015 test period	2016 test period	2017 test period
Transmission FTEs	21.50	38.60	40.00
Corporate FTEs	4.70	12.00	14.50
Total FTE requirements	**26.20**	**50.60**	**54.50**

Source: Based on Exhibit 20272-X1100, application, Table 1.5 Summary of WFMAC FTE Requirements, paragraph 34, PDF page 19.

1340. ATCO Electric explained that "… [t]o ensure that the revenue requirement calculated in this tariff application is neither impacted by the work being performed nor the revenue received related to these services, AET [ATCO Electric] has made several adjustments to its GTA schedules. On Schedules 5-3 & 25-3, the labour costs incurred by AET to provide management

services, O&M services, and route development, are shown, including affiliate overhead charges according to the Inter-Affiliate Code of Conduct. On Schedule 8-1, the revenue associated with these labour costs is recognized as an offset to revenue requirement…."[961]

1341. Revenue offsets related to the WFMAC project are addressed in Section 10 of this decision along with other affiliate revenue offsets. The Commission addressed other potential issues related to ATCO Electric's participation in the WFMAC in this part of the decision, including whether Alberta PowerLine is a "Utility Affiliate" for the purposes of the ATCO Inter-Affiliate Code of Conduct.

1342. The RPG expressed concern that ATCO Electric's involvement in WFMAC will result in the utility's customers subsidizing the operations of Alberta PowerLine. In its view, the ATCO Group Inter-Affiliate Code of Conduct requires that ATCO Electric provide services to Alberta PowerLine at no less than their fair market value (FMV).[962]

1343. The RPG characterizes the WFMAC as one of largest contracts ever entered into in Alberta transmission industry. It claims that the project is unique in its complexity, the scope of services that will be required and the fact that it was competitively bid.[963] The RPG also observed that ATCO Electric had forecast that approximately one quarter of its FTE O&M positions would be allocated to provide services to Alberta PowerLine at cost.[964]

1344. The RPG questioned whether Alberta PowerLine should be treated as a utility affiliate or a non-utility affiliate for the purposes of the Commission's inquiries.[965]

1345. The RPG also voiced concerns regarding whether ATCO Electric's involvement in the WFMAC could occur in a manner that complied with Section 3.3.1 of the ATCO Inter-Affiliate Code of Conduct respecting the sharing of employees. In doing so, it identified ATCO Electric employees' access to confidential information and coincident participation in decision-making affecting the provision of utility services to Alberta PowerLine and the operation of ATCO Electric as being problematic.[966]

1346. The RPG challenged ATCO Electric's position that it was permitted to provide shared services to Alberta PowerLine in accordance with Section 3.3 of the ATCO Inter-Affiliate Code of Conduct because both affiliate entities are regulated. The RPG submitted that the kind of regulation that each of ATCO Electric and Alberta PowerLine are subject to must be taken into account in the determination of whether both entities are Utility Affiliates for the purposes of the ATCO Inter-Affiliate Code of Conduct.[967]

1347. The RPG argued that the use of the fully burdened cost recovery mechanism proposed by ATCO Electric does not foreclose the possibility that the utility will be subsidizing Alberta PowerLine's operations. For example, the use of a fully burdened cost does not control for the fact that the driver for the cost is an individual FTEs time, which can be under-recorded. It likewise does not protect against a situation where ATCO Electric's most experienced employees

[961] Exhibit 20272-X1100, application, paragraph 34, PDF pages 18-19.
[962] Exhibit 20272-X0789, RPG evidence, paragraph 369, PDF page 123.
[963] Exhibit 20272-X0789, RPG evidence, paragraphs 378-380, PDF pages 125-126.
[964] Exhibit 20272-X0789, RPG evidence, paragraphs 385-388, PDF pages 127-128.
[965] Exhibit 20272-X0789, RPG evidence, paragraphs 392-395, PDF pages 129-130.
[966] Exhibit 20272-X0789, RPG evidence, paragraphs 396-399, PDF pages 130-131.
[967] Exhibit 20272-X0789, RPG evidence, paragraphs 406-410, PDF pages 132-133.

may be assigned to Alberta PowerLine-related tasks or instructed that Alberta PowerLine work will be given priority.[968]

1348. The RPG submitted that documentary verification and transparency were needed to protect against cross subsidization. To this end, it recommended that ATCO Electric be required to publically disclose invoices, timesheets, and schedules of services received to confirm that cross-subsidization was not occurring.[969]

1349. The RPG requested that the Commission direct ATCO Electric to refile, as part of its compliance application, a comparison of the revenue impacts resulting from the provision of services to Alberta PowerLine on a for-profit as opposed to cost recovery basis. It suggested that a multiplier of 1.5x could be applied to fully burdened costs of ATCO Electric to arrive at an approximate FMV for these services which, in turn, could be used as a placeholder forecast value pending the completion of a study to confirm market valuation. The RPG suggested that this study could be filed either with the compliance filing or at a later date if more time is required to complete it.[970]

1350. The RPG also recommended that both the revenues and costs associated with ATCO Electric's provision of services to Alberta PowerLine should be afforded deferral accounting treatment over the test period as a means of ensuring that this work was truly "revenue neutral" in terms of its impact on ratepayers.[971]

1351. In response to the RPG, ATCO Electric argued that its proposal to provide services to Alberta PowerLine on a cost recovery basis was reasonable and was consistent with the provisions of the ATCO Inter-Affiliate Code of Conduct. It submitted that:

> …. both AET[ATCO Electric] and APL [Alberta PowerLine] are regulated transmission facilities under the jurisdiction of the AUC, notwithstanding that certain aspects of Alberta Powerline operations are governed by specific provisions of the legislation. As such, transactions between AET and APL are Utility transactions. AET has entered into service agreements to provide service to APL, as it is fully entitled to do under the ATCO Group Inter-Affiliate Code of Conduct ("Code of Conduct")."
>
> Section 3.3.4 of the Code of Conduct expressly permits Shared Services to be provided by AET to APL. This is taking place pursuant to the service agreements for the WFMAC Project. Section 2.1(v) of the Code of Conduct defines "Shared Services" and expressly states that they can be provided on a Cost Recovery Basis by a Utility to an Affiliate….
>
> Finally, Section 2.1(l) of the Code of Conduct defines "Cost Recovery Basis" and, with respect to the use of personnel means the fully burdened costs of such personnel. Again, this is precisely what is occurring with respect to the services being provided by AET to APL."[972]

1352. ATCO Electric argued that the creation of a deferral account was unnecessary and that the RPG had not justified its creation. It maintained that its treatment of the associated revenues

[968] Exhibit 20272-X0789, RPG evidence, paragraphs 413-414, PDF pages 134-135.
[969] Exhibit 20272-X0789, RPG evidence, paragraphs 415-416, PDF page 135.
[970] Exhibit 20272-X0789, RPG evidence, paragraphs 422, PDF page 136.
[971] Exhibit 20272-X0789, RPG evidence, paragraphs 424, PDF page 137.
[972] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 195.

and costs will keep ratepayers neutral: all costs charged will be recovered through a revenue offset.

1353. ATCO Electric also rejected the RPG's claim that approximately one quarter of its staff will be providing services to Alberta PowerLine. It claimed that less than five per cent of ATCO Electric's annual FTE complement during the test period will provide services to Alberta PowerLine under the contemplated arrangement.

Commission findings

1354. The Commission considers that ATCO Electric's provision of services to Alberta PowerLine over the test period represents a significant allocation of the utility's resources. It is the utility's prerogative to provide these services as long as doing so does not adversely affect system safety and reliability. However, the financial impacts of the arrangement between ATCO Electric and Alberta PowerLine are nonetheless subject to Commission scrutiny because they inform the determination of just and reasonable rates. Utility rates are affected by numerous factors including whether the subject utility transacts with other regulated or non-regulated affiliates. In some cases, affiliate transactions can result in more efficient use of assets and savings realized by the use of shared services that leverage various economies. However, affiliate transactions can pose risks to ratepayers including those arising from cross-subsidization. These risks are magnified in cases where a regulated utility engages in transactions with a non-regulated affiliate.

1355. The identification and management of potential cross-subsidization risks is a primary concern in the examination of affiliate transactions. The Commission's concern in this regard is that ratepayers not be required to contribute to the success of non-regulated endeavours without compensation. The Commission's consideration of the services agreement between ATCO Electric and Alberta PowerLine is guided by the provisions of the ATCO Inter-Affiliate Code of Conduct. In this decision, the Commission will only address the provision of affiliate services during the test years. Findings in this decision are fact-specific and do not bind future determinations that may be required in future applications.

1356. In considering issues related to the provision of affiliate services by ATCO Electric to Alberta PowerLine, the Commission finds it instructive to review the objective[973] of the ATCO Group Inter-Affiliate Code of Conduct (the Code), which has frequently been referenced by parties to this proceeding:

> [T]he overall purpose of the Code is to establish standards and parameters which prohibit inappropriate Affiliate conduct, preferences or advantages, which may adversely impact the customers of regulated businesses….

1357. The parties disagreed as to how Alberta PowerLine should be characterized for the purposes of applying the ATCO Inter-Affiliate Code of Conduct. The Commission considers that while Alberta PowerLine may become (or otherwise be deemed to become) a utility as defined in the ATCO Inter-Affiliate Code of Conduct upon completion of the WFMAC, it does not currently qualify as such because it does not fall under the definition of either a "public utility"

[973] Decision 2003-040, ATCO Group Inter-Affiliate – Code of Conduct, Appendix 5, page 1.

as defined at Section 1(i) of the *Public Utilities Act*[974] or an "electric utility" as defined at Section 1(o) of the *Electric Utilities Act*.[975]

1358. The Commission considers that this finding regarding Alberta PowerLine's non-utility status is not dispositive of whether ATCO Electric may provide it with "shared services" as defined by Section 3.3.4 of the Code "to ensure that each of the Utilities and its Affiliates bears its proportionate share of costs."[976]

1359. The ATCO Inter-Affiliate Code of Conduct defines "cost recovery basis" as requiring the charging of "… fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads."[977]

1360. ATCO Electric stated that the services to be provided to Alberta PowerLine would come from a number of individuals,[978] and explained further during the hearing as follows:

> MR. DECHAMPLAIN: Mr. Wachowich, the resources that we have that are supporting the West Fort McMurray project are slivers of time for most of the individuals. There are maybe 10 to 15 people who would be full-time, you know, out of the 1,300-person workforce.[979]

1361. In another exchange with Commission counsel, Mr. DeChamplain, for ATCO Electric, confirmed that timesheets would be used to track time charged to support Alberta PowerLine's WFMAC project:

> MR. DECHAMPLAIN: When -- when we execute the project, pretty much everybody's on time sheet and they charge their time to the projects, whatever they're working on, if it's in support of Alberta PowerLine, and it goes through our review and approval time sheet process and gets charged to that project just like any other project would.[980]

1362. The affiliate overhead rate that would be applied to labour costs for construction projects is 70 per cent of the labour costs according to the Inter-Affiliate Code of Conduct, and 40 per cent otherwise.[981] Mr. DeChamplain, for ATCO Electric, in responses provided to Mr. Wachowich, counsel for the CCA, confirmed that costs for the WFMAC project would be burdened using the affiliate overhead rate and whether on a forecast or actual basis, customers would not face any risks or costs associated with the project, as explained below:[982]

> MR. DECHAMPLAIN: In arriving at the determination, what ATCO Electric wanted to do was to protect and insulate ratepayers from any costs or any risks. The amount of costs that are incurred are burdened up with our affiliate overhead rate. The amount is then backed out of any costs that are associated with the revenue requirement.

974 RSA 2000, c. P-45.
975 SA 2003, c. E-5.1
976 Decision 2003-040, Section 3.3.4 – Shared Services Permitted, page 7.
977 Decision 2003-040, Definitions, page 3.
978 Exhibit 20272-X1100, application, paragraph 6, PDF page 3.
979 Transcript, Volume 7, page 1174, lines 9-14.
980 Transcript, Volume 8, page 1334, lines 17-23.
981 Exhibit 20272-X1140, Attachment 5, Schedule 31 – Attachment 31.6, Affiliate Overhead Rate Review.
982 Transcript, Volume 7, page 1164, lines 7-22.

> So customers included in our forecast have zero costs associated with the West Fort McMurray project. When we go to do our actuals, the actuals will be coded to the affiliate cost of goods sold line. We'll burden it up with the affiliate rate, and we will back the actuals out of our costs. So both on a forecast basis and an actual basis customers are not harmed, nor do they benefit, nor are they at risk for any of the costs associated with this project.

1363. ATCO Electric's proposed affiliate overhead rate of 70 per cent being used for capital projects would be applied to labour costs, and fringe benefit costs would then be added to the cost of the proposed affiliate services costs forecast for Alberta PowerLine, as shown in Table 64 above. Table 65 shows the forecast FTEs of providing these labour services, for which ATCO Electric has indicated it will use time sheets to track labour charges.

1364. The Commission considers that RPG's concerns regarding cross-subsidization can largely be addressed by the diligent use of time sheets to track labour charges, along with the addition of fringe benefit costs, and the addition of a 70 per cent affiliate overhead rate on construction projects to address the smaller, less direct costs that are less variable and not economical to individually track.

1365. For the above reasons, the Commission finds that ATCO Electric will be permitted to provide the described services to Alberta PowerLine on a "shared services" basis as defined in the Code, provided that sufficient measures are put in place to ensure that 100 per cent cost recovery (including charges for overhead and fringe benefits) is attained by ATCO Electric over the test period.

1366. The Commission notes, based on its review of Table 64 above and a comparison of the included amounts to transmission and corporate expenses included in Transmission expense Schedule 5-3,[983] and Corporate expense Schedule 25-3[984] for affiliate cost of goods sold and for affiliate cost of goods sold overhead recovery, that there appears to be a resulting net cost to ATCO Electric arising from an error in the calculated net overhead recovery amount. On each of Schedules 5-3 and 25-3, amounts from Table 65 above are included as affiliate cost of goods sold that, in turn, include overhead recovery at 70 per cent of labour for transmission and corporate portions, respectively. It appears to the Commission that the overhead recovery amount which is netted from the fully burdened cost of labor recorded in the affiliate cost of goods sold is only calculated at 40 per cent instead of the 70 per cent included for the affiliate cost of goods sold. This results in only 40 per cent of overhead burden being recovered, with 30 per cent remaining as a cost to ATCO Electric. An example demonstrating how this error arises is provided in Appendix 5 to this decision.

1367. ATCO Electric is directed to revise the affiliate cost of goods sold overhead recovery shown on Schedule 5-3 (transmission expense) and Schedule 25-3 (corporate expense) to ensure that the level of overhead costs included in the affiliate cost of goods sold, namely 70 per cent of labour for construction projects, is also reflected in the overhead recovery. By correcting this error, the overhead amount included in the cost of providing services to WFMAC will match the overhead recovery amount, resulting in no net impact on ratepayers.

[983] Exhibit 20272-X1101, Schedule 5-3, Details of Miscellaneous Transmission Expense – Account 566
[984] Exhibit 20272-X1101, Schedule 25-3, Schedule of Corporate Administrative & General Accounts 924, 930.2, 931.1, 934 and 941.

1368. ATCO Electric is further directed to review and adjust all other items included in affiliate cost of goods sold and ensure that the overhead recovery included in the total is then offset using the same amount of overhead recovered as is recorded on Schedule 5-3 for transmission expense or Schedule 25-3 for corporate expense. As part of the compliance filing, ATCO Electric is directed to provide a schedule setting out the results of its review and all consequential adjustments arising therefrom.

1369. With regard to the RPG's concern with shared ATCO Electric staff at various levels in the organization having access to confidential information, the Commission notes that the sharing between affiliates of staff with access to confidential information is a matter already addressed through a compliance plan managed by the compliance officer, who is required to report annually to the Commission. The Commission does not consider that any further protections are required given the ongoing application and enforcement of this compliance mechanism.

1370. The RPG's request for documentation and verification to protect against cross subsidization, including public disclosure of such documentation, would result in additional regulatory requirements and entail additional costs before the need to incur such costs has been demonstrated. However, the Commission does see value in monitoring the materiality and accuracy of forecasts compared to actuals, as well as in matching costs related to affiliate services provided to Alberta PowerLine to the revenue offsets which ATCO Electric has assured the Commission will result in zero revenue requirement impacts on its ratepayers. In the Commission's view this will assure that "…both on a forecast basis and an actual basis customers are not harmed, nor do they benefit, nor are they at risk for any of the costs associated with this project."[985]

1371. For these reasons, the Commission directs ATCO Electric to provide information in the nature of that shown in tables 64 and 65, above, on costs and revenue offsets, along with detailed explanations for any differences between annual forecasts and actuals, as well as any differences in actuals between costs and revenue offsets for the year being compared. This information shall be provided as separate schedules along with the annual compliance report filed with the Commission.

1372. With regard to the RPG request for a deferral account for costs and revenues, the Commission considers that a number of the criteria, as summarized in Decision 2010-189,[986] that the Commission has said should be considered before establishing a deferral account would not be satisfied here. The Commission denies the RPG request for the deferral account for costs and revenues.

16.2 Transfer of assets to affiliates

1373. In its application, ATCO Electric explained that as a result of a reorganization into transmission and distribution divisions, "assets that were previously owned and shared by AET [ATCO Electric Transmission] and AED [ATCO Electric Distribution] were transferred at net book value effective January 1, 2015 to the appropriate division."[987] ATCO Electric went on to state that where one party's assets continue to be used by the other, an affiliate agreement outlines the payments to be made for their use. ATCO Electric confirmed that these assets

[985] Transcript Volume 7, page 1164, lines 7-22.
[986] Decision 2010-189, paragraph 106.
[987] Exhibit 20272-X1100, application, paragraph 46, PDF page 23.

consisted primarily of telecommunication equipment and buildings. The following tables summarize the transfer of assets between ATCO Electric Transmission and ATCO Electric Distribution:

Table 66. Summary of asset transfers between ATCO Electric transmission and distribution

Transfer from AED to AET			
Category	Cost	Accumulated depreciation	Net book value
	($ million)		
Land	0.2	-	0.2
Building and structures	15.7	(3.1)	12.6
Communication equipment	35.1	(18.4)	16.7
Total (per schedules 10-2 and 10-3)	**51.0**	**(21.5)**	**29.5**

Transfer from AED to AET			
Category	Cost	Accumulated depreciation	Net book value
	($ million)		
Software	(1.3)	0.2	(1.1)
Land	(2.7)	-	(2.7)
Leasehold	(1.1)	0.0	(1.1)
Building and structures	(44.5)	4.5	(40.0)
Wooden poles	(0.1)	0.0	(0.1)
Conductors – wooden poles	(0.0)	0.0	(0.0)
Substation	(0.2)	0.0	(0.2)
Communication equipment	(0.9)	0.2	(0.7)
Total (per schedules 10-2 and 10-3)	**(50.8)**	**4.9**	**(45.9)**

Source: Based on Exhibit 20272-X1100, application, Table 1.6 Asset Transfers, PDF page 24.

1374. ATCO Electric stated that the change in ownership resulting from the asset transfers between transmission and distribution "does not result in a significant change in overall costs to ratepayers as increased O&M costs are offset by a reduction in transmission capital related components for return on rate base and depreciation as well as the underlying income tax impact."[988]

1375. Interested parties did not raise concerns with respect to the asset transfers.

1376. The RPG did, however, express concerns with regard to the transfer of ATCO Electric assets to other affiliates, as identified in a response received to an IR,[989] which included the following:

> Stettler – The ATCO Electric facility in Stettler at 3809-46 avenue was transferred to ATCO Real Estate Holdings Ltd. in 2013 for $670,000 of which $460,000 was for the building. Due to growth in the region, a new facility was approved and constructed and all of ATCO Electric operations were relocated.

[988] Exhibit 20272-X1100, application, paragraph 242, PDF page 110.
[989] Exhibit 20272-X0413, response to IR AET-CCA-2015JUL10-007, PDF pages 449-456.

> Hanna – The ATCO Electric facility in Hanna at 212 Centre Street South was sold to a local church group in 2010 for $15,000. The nature of the facility was very old and small. It was no longer possible to use the site for any of ATCO Electrics operations.
>
> Peace River – The ATCO Electric facility in Peace River at the Bridgeview Industrial Park was sold in 2000 to a private company in Peace River for $325,000. The space and buildings were no longer adequate for evolving business requirements. Due to growth in the region, a new facility was approved and constructed and all of ATCO Electric operations were relocated.

1377. The RPG argued that an observer is not able to track transactions between ATCO Electric and other ATCO group members, so it must rely upon ATCO Electric's reporting of affiliate transactions as complete and correct. The RPG raised concerns as to whether these sales were conducted at fair market value and how it was determined. It also questioned the absence of identification of the purchaser and the availability of documentation, in some cases, even for recent transactions.[990]

1378. The RPG recommended that the Commission direct ATCO Electric to identify all transactions between ATCO Electric and any affiliate from 2004 to the present, and to provide adequate details on each transaction to demonstrate that it was conducted at fair market value.[991]

1379. In addition, the RPG requested that ATCO Electric be directed to identify all sales of property involving transmission in the last 10 years including evidence that these sales were conducted at fair market value, and if any sales were to ATCO group affiliates.[992]

1380. In response, ATCO Electric stated that, in accordance with the affiliate code, it must annually file the following:[993]

> …. its Affiliate Compliance Report to the AUC which identifies and reports on all affiliate transactions. The transactions reported include asset "transfers" which include a description of the transactions. The report outlines ATCO Electric's compliance plan and its compliance with the provisions of the Code. Further, the annual Affiliate Compliance Report is subject to detailed internal review and is signed off by an Officer of ATCO Electric.

1381. ATCO Electric also confirmed that the Stettler facility had been sold in the ordinary course of business at fair market value based on a market assessment prepared by an independent third party. The sale of the Stettler facility was the only transaction with an affiliate identified in the above-mentioned response to an IR. The other two sales were at fair market value to arms-length third parties. ATCO Electric submitted that the RPG's request for a direction was unnecessary.[994]

Commission findings

1382. The Commission notes that the asset transfers shown in Table 66 above relating to the ATCO Electric reorganization into transmission and distribution divisions occurred effective

[990] Exhibit 20272-X0789, RPG evidence, Section 17, paragraphs 347-368, PDF pages 119-123.
[991] Exhibit 20272-X0789, RPG evidence, paragraph 362, PDF page 122.
[992] Exhibit 20272-X0789, RPG evidence, paragraph 368, PDF page 123.
[993] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF page 189.
[994] Exhibit 20272-X1120, ATCO Electric rebuttal evidence, PDF pages 191 and 194.

January 1, 2015 and resulted in a net transfer of assets to distribution from transmission of $16.4 million based on net book value.

1383. The RPG requested that the Commission direct ATCO Electric to identify any and all transactions between ATCO Electric and any ATCO Group affiliate regarding sales of property involving transmission, covering 10 or more years of historical data, along with details to confirm these transactions were at fair market value.

1384. The Commission considers the RPG request to be unduly onerous. Additionally, as stated by ATCO Electric, annual affiliate compliance reports identifying transfers between affiliates and including corresponding descriptions are regularly filed with the Commission.

1385. For these reasons, the Commission is not persuaded that the RPG's request is reasonable in the circumstances. However, it directs ATCO Electric to provide the following information as part of all future GTA proceedings:

- Complete descriptions of all sales or transfers of ATCO Electric transmission assets occurring in the period covering actual information filed for comparison use to the test years. Information regarding identified transactions must include a description of the assets involved, a statement of the transaction value including confirmation of whether and (if applicable) how fair market value pricing was determined (including copies of all valuation reports relied upon).

- Identification of all asset transactions between ATCO Electric and an affiliate, for each comparison year of actuals or any portion thereof. For example, in the current 2015-2017 proceeding, 2012 through 2014 actuals were provided for comparative purposes. In addition, the 2015 test year forecast included a portion of 2015 YTD actuals. For this example, information should be provided for 2012 through 2015 YTD actuals.

17 Areas not individually addressed

1386. ATCO Electric requested approval of the proposed revenue requirements based on information contained in its updated application. These amounts are summarized in the table below:

Table 67. Summary of requested revenue requirement for test period

Description	Test period		
	2015	2016	2017
	($ million)		
Revenues			
Transmission tariffs	721.1	845.6	884.4
Deferral accounts	-	-	-
Total revenues	721.1	845.6	884.4
Costs			
Fuel	6.4	8.2	8.8
Operating costs	186.8	197.9	220.5
Depreciation	218.4	300.9	311.0
Return on rate base	309.2	312.1	312.3
Income tax expense	31.6	45.8	49.9
Revenue offsets	(31.3)	(19.3)	(18.1)
Total costs	721.1	845.6	884.4
Transmission tariffs	721.1	845.6	884.4
Revenue at existing rates	579.0	579.0	579.0
Increase	142.1	266.6	305.4
% Cumulative increase	24.5%	46.0%	52.8%
% Annual increase	24.5%	17.3%	4.6%

Source: Based on Exhibit 20272-X1101, Schedule 3-1 Transmission Revenues and Costs.

1387. The Commission has considered all aspects of ATCO Electric's application in making the determinations described in this decision. Readers are advised that any forecasts submitted in the application, but not specifically addressed in this decision may be considered to be approved, as filed.

1388. The Commission advises that approvals granted in relation to certain aspects of ATCO Electric's application may have impacts on amounts to be recorded in other areas (e.g., operating costs and no cost capital) despite the fact that they have not been expressly addressed in this decision. Consequently, ATCO Electric is directed to update its compliance filing for all impacts on all matters comprising its application for the test years regardless of whether they are expressly addressed herein.

18 Order

1389. It is hereby ordered that:

(1) ATCO Electric Ltd. shall refile its 2015-2017 Transmission General Tariff Application by September 30, 2016, to reflect the findings, conclusions, and directions in this decision.

Dated on August 22, 2016.

Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
ATCO Electric Ltd. - Transmission Bennett Jones LLP
AltaLink Management Ltd.
Alberta Direct Connect Consumers Association (ADC) Ackroyd LLP
Industrial Power Consumers Association of Alberta (IPCAA) Bull, Housser and Tupper LLP
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
The City of Calgary McLennan Ross Barristers & Solicitors

Alberta Utilities Commission Commission panel W. Grieve, QC, Chair B. Lyttle, Commission Member B. Romaniuk, Acting Commission Member Commission staff R. Finn (Commission counsel) D. Cherniwchan L. Mullen C. Strasser M. Kopp-van Egteren R. Armstrong, P.Eng. T. Wilde

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
ATCO Electric Ltd. L. Keough D. Sheehan	Main panel: D. DeChamplain C. Clark R. Ryder E. Jansen G. Vachon Depreciation panel: L. Kennedy D. DeChamplain E. Jansen
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC	J. Pous J. Thygesen R. Retnanandan
Office of the Utilities Consumer Advocate (UCA) T. Marriott, QC A. Preda	R. Bell
Industrial Power Consumers Association of Alberta (IPCAA) M. Keen	
The City of Calgary D. Evanchuk	
Ratepayer Group (CCA, IPCAA and Alberta Direct Connect Consumers Association (ADC)) J. Wachowich, QC	V. Bellissimo C. Chekerda T. Cline D. Levson D. Madsen R. Mikkelsen K. de Palezieux W. Tusa

Alberta Utilities Commission Commission panel W. Grieve, QC, Chair B. Lyttle, Commission Member D. Romaniuk, Acting Commission Member Commission staff R. Finn (Commission counsel) D. Cherniwchan L. Mullen C. Strasser M. Kopp-van Egteren R. Armstrong, P.Eng. T. Wilde

Appendix 3 – Motions and procedural rulings

(return to text)

The following is a summary of rulings and procedural requests during the proceeding:

(1) By letter dated April 29, 2015, the Commission granted ATCO Electric's request for confidential treatment of ATCO Electric's master service agreement with Wipro Solutions Canada Limited (Wipro) as an information technology services provider and also a report prepared by KPMG, retained on behalf of ATCO Electric, to conduct a price validation and review comparing the MSA pricing and commercial terms and conditions with market pricing and practices (KPMG report). Exhibit 20272-X0181.

(2) By letter dated May 1, 2015, the Commission issued a ruling on a CCA motion. The ruling dealt with the following three matters: (1) the Commission directed that the 2017 test year shall not be excluded from the current application, however, the onus remained with ATCO Electric to support all aspects of the application, including the reasonableness of forecasts for each of the test years, and demonstrating that it is in the public interest to include each test year in its application; (2) regarding the depreciation information, the Commission directed ATCO Electric to file the 2014 actual results by May 1, 2015 and updated schedules reflecting the depreciation parameters in the 2014 Depreciation Study and the 2014 actual results by May 8, 2015; and (3) the Commission directed ATCO Electric to file the Hanna Regional Transmission Development (HRTD) audit, which was submitted in the current application, as part of a proceeding the Commission would be establishing in due course to address the audit, as detailed in Direction 58 of Decision 2013-358. The Commission declined, in this proceeding, to evaluate the sufficiency of the audit with respect to its compliance with the requirements of Direction 58 of Decision 2013-358, and it would not consider the question of what party will ultimately bear the cost of the audit in this proceeding. Exhibit 20272-X0182.

(3) By letter dated May 8, 2015, the Commission granted ATCO Electric's request for an extension of the deadline for filing updated schedules reflecting the depreciation parameters in the 2014 Depreciation Study and the 2014 actual results. Exhibit 20272-X0213.

(4) By letter dated May 11, 2015, the Commission granted ATCO Electric's request to provide the confidential information in electronic format instead of the paper format directed by the earlier ruling to parties who had signed confidentiality agreements. Exhibit 20272-X0215.

(5) By letter dated June 19, 2015, the Commission established a revised proceeding schedule which incorporated separate, parallel depreciation and non-depreciation process steps and deadlines, and which addressed multiple requests from the UCA, ATCO Electric and the CCA. Exhibit 20272-X0245.

(6) By letter dated June 30, 2015, the Commission granted ATCO Electric's request for an extension of the deadline for filing responses to Round 1 information requests, and the CCA's request for depreciation schedule adjustments. Exhibit 20272-X0248.

(7) By letter dated August 4, 2015, the Commission granted ATCO Electric's request for confidential treatment of certain responses to June 8, 2015 information requests on the WFMAC

project, vendor rates and pricing, proprietary designs, and project milestone dates. Exhibit 20272-X0450.

(8) By letter dated August 7, 2015, the Commission denied ATCO Electric's request to move the ATCO Electric Transmission GTA hearing date into the October/November dates scheduled for the ATCO Electric Distribution capital tracker proceeding due to outstanding procedural motions and related processes. Exhibit 20272-X0248.

(9) By letter dated August 12, 2015, the Commission ruled on the UCA and CCA motions to compel ATCO Electric to provide full and adequate responses to certain information requests. The Commission directed ATCO Electric to provide additional information for adequate response to the information requests submitted by the UCA, the CCA, and the AUC. Exhibit 20272-X0479.

(10) By letter dated September 3, 2015, the Commission ruled on the CCA motion to compel ATCO Electric to provide full and adequate responses to certain depreciation information requests. The Commission directed ATCO Electric to provide additional information for adequate response to the information requests submitted by the CCA, and the AUC. Exhibit 20272-X0514.

(11) By letter dated September 14, 2015, the Commission granted ATCO Electric's request for confidential treatment of certain additional responses to the June 8, 2015 information requests on vendor rates and pricing. The Commission also directed ATCO Electric to provide the outstanding O&U filing, an updated and complete depreciation study, and additional FTE information required for compliance with an earlier Commission ruling. The Commission also updated the proceeding schedule to re-combine the separate, parallel depreciation and non-depreciation process steps and deadlines which were no longer required following consideration of process submissions from ATCO Electric and the CCA. Exhibit 20272-X0521.

(12) By letter dated October 28, 2015, the Commission established a common license fee proceeding to address license fee costs for the ATCO Electric Transmission GTA and the ATCO Pipelines GRA (Proceeding 3577). Exhibit 20272-X0617.

(13) By letter dated October 30, 2015, the Commission granted ATCO Electric's request for an extension of the deadline for filing responses to certain Round 2 information requests. Exhibit 20272-X0619.

(14) By letter dated November 4, 2015, the Commission granted ATCO Electric's request for confidential treatment of certain responses to the October 16, 2015 information requests on vendor rates and pricing, project milestones, technical information, and proprietary information. Exhibit 20272-X0661.

(15) By letter dated November 10, 2015, the Commission granted ATCO Electric's request for confidential treatment of certain additional responses to the October 16, 2015 information requests on the vendor rates and pricing. Exhibit 20272-X0675.

(16) By letter dated November 26, 2015, the Commission ruled on the Calgary motion to compel ATCO Electric to provide full and adequate responses to certain information requests. The Commission directed ATCO Electric to provide additional information for adequate response to the information requests submitted by Calgary. In addition, the Commission granted

ATCO Electric's request for confidential treatment of certain additional responses to the October 16, 2015 information requests on vendor rates and pricing. Exhibit 20272-X0689.

(17) By letter dated December 4, 2015, the Commission ruled on the UCA motion on the procedural consequences of ATCO Electric's workforce reduction. The Commission directed ATCO Electric to provide additional information on the impacts of the organizational change and workforce reductions and a revised version of its complete application. The Commission also updated the proceeding schedule to accommodate an additional round of information requests and to reschedule the hearing. Exhibit 20272-X0699.

(18) By letter dated January 15, 2016, the Commission granted ATCO Electric's request for confidential treatment of certain responses to the December 30, 2015 Round 4 information requests on vendor rates and pricing. Exhibit 20272-X0774.

(19) By letter dated May 3, 2016, the Commission granted the CCA's request for an extension of the deadline for filing of argument and reply argument. Exhibit 20272-X1293.

Appendix 4 – Summary of Commission directions addressed in application

(return to text)

This section is provided for the convenience of readers and outlines the directions from Decision 2013-358 (ATCO Electric Ltd. 2013-2014 Transmission GTA) that the Commission finds have been satisfied. In the event of any difference between the directions in this section and those in the main body of Decision 2013-358, the wording in the main body of Decision 2013-358 shall prevail.

1. The Commission finds the material included in the revenue requirement supporting schedules in Exhibit 188.02 to be helpful and necessary to assist in validating the accuracy of the revenue requirement calculations. This material should have been provided as part of the omissions and updates filing to support the revised revenue requirements, just as the revenue requirements included in the initial application were supported by the information in Exhibit 3. The Commission directs ATCO Electric, in any future general tariff applications (GTA) where an omissions and updates filing is submitted, to include all detailed supporting revenue requirement schedules, as part of the omissions and updates filing, in Microsoft Excel format with all links and cross references intact. ..... Paragraph 13

2. The Commission finds the information provided by ATCO Electric in Attachment 5 of Section 31 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 33 of Decision 2011-134. The Commission directs ATCO Electric, in its next GTA, to file applied-for, actual and approved amounts for the years 2005 through to and including the relevant test years as part of the application. ..... Paragraph 19

3. The Commission finds that the information provided by ATCO Electric in Attachment 2 of Section 5 of the application demonstrates that ATCO Electric has complied with the direction included in paragraph 343 of Decision 2011-134. The Commission directs ATCO Electric to update the information in Attachment 2 of Section 5, if necessary, to reflect the final forecast amounts for 2013 and 2014 that are included in the compliance filing. The Commission reminds ATCO Electric that the direction included in paragraph 343 of Decision 2011-134 has no end date so ATCO Electric is still bound by this direction with respect to future applications. ..... Paragraph 23

24. On this basis, the Commission rejects the CCA's recommendation that ATCO Electric provide, in its next GTA, an assessment of whether its health and safety standards and practices, and associated costs, are similar to those of the other TFOs. While the overall costs incurred for safety are difficult to quantify, the Commission directs ATCO Electric, in its next GTA, to identify any specific incremental costs that are included for safety, and to make sure these incremental costs are justified. ..... Paragraph 260

25. The Commission directs ATCO Electric to provide, in its next GTA, an estimate of the costs and benefits associated with corrective and emergency maintenance procedures, to support its forecast labour and non-labour costs. It also directs ATCO Electric, as part of its next transmission GTA, to include information on how it evaluates all of the costs associated with its maintenance activities, as it explained in the quote in paragraph 281 of this decision. ..... Paragraph 284

27. The Commission is interested in how successful this program will be and directs ATCO Electric, in its next GTA, to include an update on the status of this incentive allowance program. Such an update should include, but not be limited to, information on how many of the forecast 32 crew members actually signed up for the program in late 2012, how many forfeited the allowance by leaving before the 24-month period, and how many are still eligible for the incentive allowance payment. ATCO Electric should also indicate whether it intends to continue and/or vary the program as part of its next GTA. ..... Paragraph 302

31. However, parties would benefit from ATCO Electric preparing an update to the annual provision for true-up, and the Commission consequently directs ATCO Electric to prepare such an update at the time of its next depreciation study. ..... Paragraph 334

36. The Commission directs ATCO Electric, as part of its next GTA, to provide an update on the expected future use of the Vegreville land, but otherwise approves these 2011 rate base additions as filed, subject to any future adjustments that may arise as a result of the true-up of any placeholders. ..... Paragraph 409

38. In Section 11.3 of the decision, the Commission considered a similar request from the RPG to coordinate with the AESO in respect of direct assigned capital projects. Recognizing that the AESO is legislatively responsible for system planning, the Commission nevertheless indicated support for the RPG's recommendation that TFOs and the AESO work together to prioritize and coordinate their projects on a global basis, and the Commission encouraged ATCO Electric and the AESO to do so. As ATCO Electric has indicated that it already consults with the AESO respecting the timing and need for capital maintenance projects, the Commission does not consider it necessary to further direct ATCO Electric to do what it is already doing. The Commission expects that ATCO Electric will continue to consult with the AESO regarding its capital maintenance projects and will do so in consideration of the best interests of its customers, and with the objective of avoiding needless expense. The Commission would like further information regarding these consultations and accordingly directs ATCO Electric to provide a report, as part of its next GTA, describing the consultations that it has engaged in with the AESO regarding its capital maintenance projects and outlining the outcome of these consultations in respect of the capital maintenance projects it has proposed. ..... Paragraph 424

39. Notwithstanding, based on the information provided for this project on the record of this proceeding, the Commission is not prepared to approve this entire project which, according to ATCO Electric, is an annual program for the next 10 to 15 years. The Commission has only approved the forecast expenditures and additions for the years 2013 and 2014 for the two lines identified as requiring immediate attention. In the event that ATCO Electric intends to continue with this project as indicated for the next 10 to 15 years, ATCO Electric is directed to bring forward a substantive business case and request approval in its next GTA for the forecast expenditures and additions for this project. ..... Paragraph 444

70. The Commission considers that part of the prudent management of the debt costs includes exploring and obtaining any sort of assistance that results in a reduction to debenture rates. Even a small reduction in debt rates, when applied to a large debt amount over a long period of time, can result in significant savings in interest costs. The federal government has provided loan guarantees for certain transmission projects in eastern

Canada, and the Commission finds that ATCO Electric should investigate the possibility of obtaining federal and provincial government loan guarantees and assessing the impact on debt costs. The Commission directs ATCO Electric, in its next GTA, to provide details about its efforts to obtain federal and provincial government loan guarantees, and the assessment of any such guarantees. ..... Paragraph 912

89. With respect to the current administrative building located in Drumheller and its use once the new two story administrative and technical building is built at the warehouse site, Mr. Babyn stated that it will continue to be used until the new building is in service in 2014, at which time the continued use will be assessed. Considering the uncertainty of the future use of the current administrative building in Drumheller, the Commission directs ATCO Electric, in its next GTA, to include an update on the status of the current administrative building in Drumheller and how, if it is included in rate base in the next GTA, such a facility is being used in the provision of transmission utility service. ..... Paragraph 1069

90. The Commission directs ATCO Electric, in its next transmission GTA and next annual transmission deferral account application, to include the following additional information with respect to any individual direct assigned capital project that has a forecast capital cost in excess of $5.0 million:

- project milestone schedules and the timing of capital expenditures
- AESO change order requests and authorizations
- cost estimates at the stages described in paragraph 1082 of this decision
- cost estimates by the categories described in paragraph 1084 of this decision
- the preliminary engineering costs included in the cost estimates
- the detailed engineering costs included in the cost estimates
- schedules of project attributes, for both transmission line projects and substation projects, similar to the information provided in response to information request IPCAA-AE-008(c)
- parametric values that are derived through the use of parametric estimating techniques
- the current AESO functional specifications
- bulk transmission line optimization studies where required by ISO Rule 502.2
- post completion reports
- 60-day and 150-day reports that are filed in response to the AESO's rules ..... Paragraph 1096

This section is provided for the convenience of readers and outlines the directions from Decision 2013-417 (Utility Asset Disposition) that the Commission finds have been satisfied. In the event of any difference between the directions in this section and those in the main body of Decision 2013-417, the wording in the main body of Decision 2013-417 shall prevail.

2. 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 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. .. .. Paragraph 327

This section is provided for the convenience of readers and outlines the directions from Decision 2014-167 (ATCO Electric Ltd. 2013-2014 Transmission GTA Compliance Filing) that the Commission finds have been satisfied. In the event of any difference between the directions in this section and those in the main body of Decision 2014-167, the wording in the main body of Decision 2014-167 shall prevail.

4. However, the Commission agrees with the comments of the CCA that the information provided in the response to information request AUC-AE-14 provides the level of detail that should have been included as support for ATCO Electric's contribution forecast, in its original application. The Commission directs ATCO Electric to incorporate the form and content set out in AUC-AE-14, respecting its forecast contributions, in its future GTAs. ..... Paragraph 61

This section is provided for the convenience of readers and outlines the directions from Decision 2014-283 (ATCO Electric 2012 Transmission Deferral Account and Annual Filing) that the Commission finds have been satisfied. In the event of any difference between the directions in this section and those in the main body of Decision 2014-283, the wording in the main body of Decision 2014-283 shall prevail.

5. The Commission finds that the high volume of material filed in this proceeding reflected the magnitude of the cost variances that ATCO experienced for the projects included in the current application. However, for the purposes of future applications, including a key decision matrix and risk registry in the application may assist both the applicants and the interveners in managing and focusing on the documentation necessary for testing future transmission project deferral account reconciliation applications. The Commission directs

ATCO to develop a proposal for a key decision matrix and to review its risk registry practices and to fully describe such proposal and review in either its next GTA or its next transmission deferral account application, whichever comes first. ..... Paragraph 108

6. Accordingly, the Commission directs ATCO to implement contingency allowances based on express risk register-based approaches to determining contingency allowance amounts for all direct assign projects not currently underway, as soon as practically possible. The Commission further directs ATCO to report on its progress towards the implementation of a risk register-based contingency allowance determination in either its next GTA or its next transmission deferral account application, whichever comes first. ..... Paragraph 124

Appendix 5 – Example of net overhead recovery error

(return to text)

Summary 2016 affiliate services forecast costs for WFMAC project

GTA category / reference	2016 test period
	($ million)
Labour	4.25
Fringe	0.85
Overhead	2.97
(B) Schedule 5-3 USA 566 Line 17	**8.07**

Source: Based on Exhibit 20272-X1100, application, Table 1.4 Summary of WFMAC Affiliate Services, paragraph 34, PDF page 19.

On Schedule 5-3

Line 17 for 2016 includes $8.1million, which corresponds to the $8.07 million shown above subject to rounding.

But, line 22 for 2016 includes ($1.7) million instead of the $2.97 million shown above.

Calculation
The $4.25 million of labour x 70% affiliate overhead = $2.97 million.
Using 40 per cent overhead loading leads to the $1.7 million found in line 22 of Schedule 5-3

The net effect for 2016 in this example provided is that $8.1 million is added to transmission expense in Account 566 for Alberta PowerLine affiliate services which includes the $2.97 million of overhead burden but, by only recording an overhead recovery of $1.7 million as an offset on Schedule 5-3, the 2016 revenue requirement includes a net impact or cost of $1.27 million resulting from the overhead recover error.

The intended result of no net impact on revenue requirement is not achieved due to this error.

Appendix 6 – Summary of Commission directions – current direction

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 above ruling, the Commission determined that the HRTD audit, prepared under ATCO Electric's direction and submitted with its application, would not be evaluated in the current proceeding as to its compliance with Direction 58. The Commission also stated that no decision would be made in the present proceeding as to which party would bear the cost of the audit. ATCO Electric is reminded that Direction 58 remains outstanding as does the direction in the above ruling requiring that ATCO Electric file its HRTD audit as part of a future proceeding. ATCO Electric is directed to file the HRTD audit with its forthcoming transmission deferral account application for the HRTD project.. ..... Paragraph 62
2. The Commission understands the above statement to mean that ATCO Electric considered itself to be fully staffed, with no vacant positions, as of year-end 2015. Given this, the Commission directs ATCO Electric to use its 2015 actual FTEs as the approved complement for 2015. ..... Paragraph 78
3. The Commission previously understood that the removal of positions a month prior to the end of the year would result in a small fraction of an FTE being removed in 2015. However, it finds that Mr. Jansen's response in questioning did not address the apparent discrepancy in the O&M and capital allocations for certain FTEs removed in 2016 and 2017 as part of the workforce reduction. ATCO Electric is directed to correct the response to AET-AUC-2015JUN08-17(i) February 23 update such that the O&M and capital split for a position eliminated in the workforce reduction matches the O&M and capital split previously forecast for that position. ATCO Electric is also directed to update any impact to its O&M and capital forecast costs for the 2016 and 2017 test period as a result of these changes.. ..... Paragraph 81
4. Once this response has been corrected, ATCO Electric is directed to identify, in the updated exhibit, the positions included in the 941 headcount in December 2015. Those positions and the FTE complement are approved as ATCO Electric's opening 2016 FTE complement. ..... Paragraph 82
5. The Commission recognizes that ATCO Electric has filed numerous updates to forecasts for 2015, reflecting both updated costs and FTE complements. The work completed on projects in 2015 that occurred beyond the mid-year point will be included in actual costs when ATCO Electric files an application to settle its 2015 deferral balances. The Commission directs ATCO Electric to use its actual 2015 FTEs as the approved forecast FTE complement for that year. The Commission rejects the RPG's recommendation to direct ATCO Electric to revise its reported mid-year complement for 2015 to reflect terminations that occurred throughout the year. The Commission will assess the prudency of direct assigned project capital expenditures, including the prudency of labour costs related to the terminated positions, in a future DACDA filed by ATCO Electric. ..... Paragraph 100
6. The Commission is of the view that a utility should apply the mid-year convention to the removal of an FTE in the year of its forecasted removal if the utility is not expecting to

fill the position through promotion or an external hire going forward. This treatment should be applied regardless of the underlying reason for the FTE's removal. The Commission considers that such treatment reflects reciprocal application of the mid-year convention used when the Commission approves a forecast addition to a utility's FTE complement. The Commission directs ATCO Electric to apply the mid-year convention to any and all FTE removals and associated costs forecasted for 2016 and 2017. ..... Paragraph 101

7. At the oral hearing, ATCO Electric confirmed that it would not be providing VPP payments to its employees for 2015. The Commission, therefore, directs that ATCO Electric adjust its forecast VPP amounts for this test year to zero, based on actuals. ..... Paragraph 185

8. The Commission directs ATCO Electric to set up a VPP reserve account in its no cost capital schedules in Section 29 of ATCO Electric's revenue requirement schedules. Regarding the mechanics of the reserve account, ATCO Electric will not be eligible to recover costs in excess of the approved VPP forecast amounts for a given year, and will not be permitted to carry over unused VPP funds for use in future years of the current application. Approved, but unused, VPP amounts in any given GTA test period will be added to the VPP reserve account for the next GTA test period. In the Commission's view, this approach will address the legitimate need to maintain funding for ATCO Electric's VPP in support of its recruitment, retention and operational performance goals, while insuring that any incentive to withhold VPP amounts otherwise payable to eligible employees based on their performance, in order to increase the utility's retained earnings, is removed. ..... Paragraph 192

9. In the Commission's view, the Alberta CPI update provided by the RPG at the oral hearing represents the most up to date information available for use in determining past and forecast "other inflation" rates for the test years. The Commission accepts the RPG's recommended "other inflation" rates of 1.6 per cent and 1.9 per cent for 2016 and 2017, respectively. Based on the Alberta Government's 2015-16 Third Quarter Update, the Commission finds that it is reasonable to update the 2015 rate to 1.1 per cent, as well. ATCO Electric is directed to update its other inflation rates to 1.1 per cent for 2015, 1.6 per cent for 2016 and 1.9 per cent for 2017. ..... Paragraph 201

10. ATCO Electric is to revise its "other inflation" rates as directed here only after adjustments have been made pursuant to all other directions in this decision. .... Paragraph 202

11. The Commission approves ATCO Electric's use of a weighted average approach to calculate its contractor and capital inflation rates. The Commission directed ATCO Electric to update its "other" and labour inflation rates in sections 5.2.1 and 5.3.1 above. The Commission finds that the approved out-of-scope labour inflation rate best reflects the current contractor labour market. Based on the out-of-scope labour inflation and "other inflation" rates the Commission has approved in previous sections of this decision, ATCO Electric is directed to use a contractor and capital inflation rate of 1.1 per cent in 2016 and 1.3 per cent in 2017. ..... Paragraph 210

12. As with the other inflation adjustments identified above, ATCO Electric is to apply changes to its contractor and capital inflation rate after adjustments from all other directions contained in this decision have been made. ..... Paragraph 211

13. Based on these determinations in Decision 21029-D01-2016, issued on June 30, 2016, the Commission denies the proposed corporate licence fee placeholders of $2.7 million, $3.1 million and $4.7 million for 2015, 2016 and 2017, respectively. The Commission directs ATCO Electric, in the compliance filing, to remove these placeholder amounts from the revenue requirement in each of the test years. ..... Paragraph 223

14. The Commission directs ATCO Electric, in the compliance filing, to confirm whether it has proposed an IT cost placeholder in relation to the IT common matters proceeding which is examining IT pricing. ATCO Electric is directed to prepare and file a schedule, in the compliance filing, summarizing the IT costs included in the application by test year, within each cost area, being O&M, ES&G, and capital, displaying the accounts used for these charges in each cost area. ..... Paragraph 228

15. The Commission finds that the test years in the current application shall have placeholder treatment for defined benefit pension costs and that these costs for 2015, 2016 and 2017 will be determined in Proceeding 21831. The Commission therefore directs ATCO Electric to update its revised placeholder schedule (Exhibit 20272-X1136, Attachment 2) and file the updated schedule in the compliance filing to this decision. ..... Paragraph 237

16. It appears to the Commission that ATCO Electric, in addition to being unable to control the weather and resulting growing seasons, is unable to reasonably rely on the availability of contractors to perform the work it has forecasted. The Commission considers that ATCO Electric's customers should not bear a disproportionate share of the risk that ATCO Electric may be unable to complete its forecasted VM work. Therefore, the Commission directs ATCO Electric to set up a reserve account for vegetation management in its no cost capital schedules in Section 29 of its revenue requirement schedules. Regarding the mechanics of the reserve account, ATCO Electric will be required to set off amounts spent in excess of approved forecasts for a given test year against amounts included in approved forecasts for subsequent years within the test period. Approved, but unused, VM amounts in any given GTA test period will be added to the VM reserve account for the next GTA test period. ..... Paragraph 261

17. In view of the foregoing, the Commission rejects ATCO Electric's proposed telecommunication cost allocation methodology and directs it to continue to use the allocation percentages approved in its 2013-2014 GTA. ..... Paragraph 296

18. On the basis of the foregoing, the Commission denies ATCO Electric's proposed use of forecast information in its actuarial database for the purpose of developing depreciation parameters and directs ATCO Electric in its next depreciation study to revert to its currently approved methodology which provides for the use of forecast capital additions solely for the purpose of determining depreciation rates. ..... Paragraph 400

19. For the purposes of calculating its depreciation rates for the test years, ATCO Electric is directed in its compliance filing to this decision, to incorporate the capital additions approved elsewhere in this decision in calculating the aged plant account balances upon which each test year's depreciation rates will be based. ..... Paragraph 402

20. The Commission directs ATCO Electric to apply the mid-year convention in its revenue requirement calculations with respect to its depreciation expense calculations for all projects forecast to be capitalized in a given year and to reflect this direction in its compliance filing to this decision for regulatory purposes. In doing so, the utility is also directed to afford EATL-related depreciation mid-year convention treatment in respect of 2015, the year it was energized. ATCO Electric is further directed to continue applying

the mid-year convention for regulatory purposes unless otherwise ordered by the Commission. ..... Paragraph 412

21. On that basis, ATCO Electric is directed to identify and create a subaccount category for any USA account that now includes, and in the future will include, assets constructed to comply with ISO Rule 502.2, including any assets or capital projects constructed before the ISO rule came into effect, where projects have been constructed under the assumption that ISO Rule 502.2 would be adopted. ATCO Electric is directed to comply with this finding at the time of its next depreciation study. ..... Paragraph 424

22. ATCO Electric is directed to maintain its approved 75-R3 life-curve for Account 451 (USA 350.1) – transmission – land rights in its compliance filing to this decision. ..... Paragraph 440

23. For these reasons, the Commission considers there to be insufficient support for a change to the approved life-curve combination of 53-R3 for this account. ATCO Electric is directed to incorporate depreciation parameters of 53-R3 for Account 457 (USA 353) – transmission – substation equipment – AC in its compliance filing to this decision. ..... Paragraph 492

24. The Commission finds Mr. Pous' recommendation to be reasonable given the new composition of this account. ATCO Electric is directed to incorporate a life-curve of 50-R2.5 for Account 482 (USA 390) – general plant – structures and improvements, in its compliance filing to this decision. ..... Paragraph 509

25. ATCO Electric is directed to incorporate a 10-SQ life-curve for Account 496.1 – general plant – software – major and a 7-SQ life-curve for Account 496.2 – general plant – software – minor and to incorporate these findings in its compliance filing to this decision. The 3-SQ life-curve for Account 496.3 – general plant – software – desktop is approved. ..... Paragraph 529

26. For these reasons, the Commission directs ATCO Electric to maintain its currently approved net salvage percentage of -90.0 in its compliance filing to this decision for Account 453 (USA 355) – transmission – poles and fixtures (wooden). ..... Paragraph 550

27. At the same time, the Commission wishes to obtain a better understanding of why ATCO Electric's costs of retirement for this account appear to significantly exceed that of industry peers and considers it would be in the public interest and of considerable benefit to the Commission for ATCO Electric to include a detailed explanation for this in its next depreciation study. ATCO Electric is directed to provide the noted explanation in its next depreciation study. ..... Paragraph 551

28. The Commission directs ATCO Electric to incorporate a net salvage of -30.0 per cent for Account 454.1 (USA 356) – transmission – overhead conductors towers (steel towers), in its compliance filing to this decision. ..... Paragraph 560

29. The Commission directs ATCO Electric to incorporate a net salvage of -25.0 per cent for Account 455.1 (USA 354) – transmission – towers and fixtures (steel) in its compliance filing to this decision. ..... Paragraph 571

30. The Commission accepts the net salvage percentage of -15.0 proposed by Mr. Pous and observes that this figure is within the range of peer utility net salvage percentages. The Commission directs ATCO Electric to implement a net salvage of -15.0 per cent in its compliance filing to this decision for Account 457 (USA 353) – transmission – substation equipment – AC. ..... Paragraph 583

31. Until sufficient actuarial data supports an independent determination of service life characteristics, ATCO Electric is directed to incorporate a net salvage of -15.0 per cent for Account 457.1 (USA 353) – transmission – HVDC conductors towers in its compliance filing to this decision. ..... Paragraph 587

32. Until there is sufficient actuarial data to support an independent determination of net salvage characteristics, ATCO Electric is directed to incorporate, for its McNeill convertor station assets, net salvage in the amount of -90.0 per cent for Account 453.02 (USA 355) – poles and fixtures; -50.0 per cent for Account 454.02 (USA 356) – overhead conductors poles; and 15.0 per cent for Account 457.02 (USA 356) – substation equipment. ..... Paragraph 599

33. ATCO Electric is directed to use its approved net salvage of 0.0 per cent for Account 486 (USA 353.1) – general plant – communications structures and equipment in its compliance filing to this decision. ..... Paragraph 615

34. The Commission considers that the operating conditions that assets in these two new accounts will be subject to, should result in shorter service lives but, as there was no retirement rate analysis provided for these two accounts, it directs ATCO Electric to apply life-curve parameters consistent with those approved for the accounts with which the new accounts were previously associated. ..... Paragraph 629

35. On this basis, the Commission directs ATCO Electric to incorporate a 9-L2 life-curve for Account 484.05 (USA 392.5) – general plant – transportation equipment – category 5; and a 18-SO life curve for Account 484.06 (USA 392.6) – general plant – transportation equipment – category 6 in its compliance filing to this decision. ..... Paragraph 630

36. The Commission finds that the results of the net salvage studies for these two accounts do not support the proposed reductions in net salvage percentages from those approved and directs ATCO Electric to maintain the approved net salvage percentages for Account 484.03 (USA 392.3) – category 3 in the amount of 20.0 per cent and Account 484.04 (USA 392.4) – category 4 in the amount of 20.0 per cent in its compliance filing to this decision. ..... Paragraph 633

37. Although the Commission agrees that the operating conditions for equipment in the two new transportation subaccounts should result in lower gross salvage, given the lack of a net salvage study, the Commission finds it both reasonable and necessary to direct ATCO Electric to apply net salvage percentages consistent with those approved for the accounts with which the new accounts were previously associated. ..... Paragraph 634

38. On this basis, the Commission directs ATCO Electric to apply a 10.0 per cent net salvage for Account 484.05 (USA 392.5) – general plant – transportation equipment – category 5, and a 20.0 per cent net salvage for Account 484.06 (USA 392.6) – general plant – transportation equipment – category 6 in its compliance filing to this decision. ..... Paragraph 635

39. On that basis, the Commission directs ATCO Electric to incorporate life-curve parameters of 10-SQ for Account 485.01 – general plant – tools and instruments – category 1 and denies the establishment of Account 485.02 – general plant – tools and instruments – category 2. ..... Paragraph 644

40. ATCO Electric is directed to maintain a single account for all its tools and instrument type-assets and to incorporate a life-curve of 10-SQ for Account 485.01 – general plant – tools and instruments in its compliance filing to this decision. ..... Paragraph 645

41. However, as part of ATCO Electric's compliance filing, the Commission requires confirmation that ATCO Electric's calculated accumulated depreciation balances related to life and net salvage as of December 2017 are correct in that approximately $12.7 million in life and net negative salvage remains to be recovered in the year 2018 and beyond. ATCO Electric is directed to provide the requested confirmation and explain why the unrecovered balance is so large. ATCO Electric is also directed to describe the proposed method and period of recovery of the $12.7 million. ..... Paragraph 661

42. The Commission, as part of ATCO Electric's compliance filing, also directs that the year of final retirement of 2018 be reflected in the utility's GTA schedules along with any revisions required as a result of the direction in the paragraph above. ..... Paragraph 662

43. For this reason, the Commission directs ATCO Electric to confirm the currently approved negative net salvage percentage of the Fawcet River Account 447 (USA 346) - miscellaneous electrical equipment is -22.0 per cent and that no change has been requested for this account with respect to negative net salvage for the 2015-2017 test years. ..... Paragraph 668

44. The Commission considers that the purpose of the direct assigned capital projects deferral account is to protect both ATCO Electric and customers against all revenue requirement impacts related to differences between actual and forecasted direct assigned project costs. The Commission also considers that this includes any and all differences related to income tax and its various components, as ATCO Electric acknowledged in its 2013-2014 GTA. To the extent that there are differences between actual and forecast costs for ES&G and removal and abandonment costs that relate to direct assigned projects, the Commission finds that these should be accounted for in the 2013-2014 DACDA. The Commission directs ATCO Electric, in the compliance filing, to identify and provide these differences. The Commission also directs ATCO Electric to indicate whether these differences have been reflected in the current DACDA application and, if not, to describe how ATCO Electric will reflect them in that proceeding. ..... Paragraph 697

45. Based on this statement, the Commission considers that customers will receive the benefit of the rolling start adjustment through the 2013-2014 DACDA. The Commission directs ATCO Electric, as part of the compliance filing, to demonstrate where this benefit is reflected in the ongoing 2013-2014 DACDA proceeding. ..... Paragraph 700

46. The Commission notes that determinations on telecommunications cost allocations found at Section 7.3 of this decision may affect proposed revenue offsets considered under this section for telecommunications services provided to ATCO Electric Ltd.'s distribution arm. ATCO Electric is directed to incorporate those changes into the compliance filing. ..... Paragraph 708

47. For the above reasons, the Commission considers that affiliate overhead rates should be examined as part of the next GTA proceeding to determine whether they are adequate. The Commission directs ATCO Electric to provide a detailed assessment of affiliate overhead burden rates comparing the current rates applied and their supporting basis, to the forecast effective rate that results from forecast overhead costs and related forecast activity levels. An examination of five years of historical information shall be incorporated for comparison purposes. ..... Paragraph 713

48. The Commission finds that there is insufficient information on the record of this proceeding to approve the requested rate base additions for 2013 and 2014 for the projects included in Table 35, above. Accordingly, ATCO Electric is directed to remove

the capital additions from opening rate base in the compliance filing and to provide business cases for the work that was actually completed in 2013 and 2014 for those projects. The Commission will re-evaluate the requested capital additions for these projects upon review of the variance explanations and/or business cases provided in the compliance filing. ..... Paragraph 874

49. Consistent with the Commission's findings in Section 11.4.1 above, there is a preference for the best available information when evaluating requested revenue requirement cost components. Accordingly, ATCO Electric is directed to update the direct assigned capital forecasts as proposed for the increase in the EATL forecast capital expenditures and additions, in the compliance filing. ..... Paragraph 884

50. The Commission finds that ATCO Electric has provided insufficient information on the record of this proceeding for the Commission to determine the reasonableness of the forecast costs for these projects. Accordingly, the Commission directs ATCO Electric to remove all forecast capital expenditures and additions, and related costs with respect to the Arcenciel Synchronous Condenser, Edith Lake to Sarah Lake 144-kV Line Upgrade, Salt Creek 144-240-kV Substation, Livock 144-240-kV Substation, Cold Lake Development, St. Paul Area – Watt Lake and Whitby Lake Substations and Kitscoty Area Development projects from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision. ..... Paragraph 897

51. The Commission considers that the schedule changes that have occurred to date and the fact that several projects are currently on hold and still under review by the AESO, suggest that it is very unlikely that any of the identified capital projects will actually be initiated during the test period. Accordingly, the Commission denies the forecast capital expenditures for these projects for the purposes of determining ATCO Electric's revenue requirement in 2016 and 2017. The Commission directs ATCO Electric to remove the forecast capital expenditures and related project costs from its forecast 2016 and 2017 revenue requirement, in the compliance filing to this decision. ..... Paragraph 914

52. Accordingly, the Commission directs ATCO Electric to reduce its forecast capital expenditures in 2017 by $9.5 million for the purpose of determining ATCO Electric's revenue requirement in the compliance filing to this decision. ..... Paragraph 931

53. The most up-to-date evidence on the record for this project is that it is on hold until the AESO completes a review of the need for, and timing of, the project. After the review is complete, it is possible that the project could be cancelled. ATCO Electric has nonetheless forecast $0.8 million in capital expenditures in 2017. The Commission finds there is insufficient information on the record of this proceeding to determine the reasonableness of the forecast expenditures. The Commission approves the forecast capital expenditures as a placeholder and directs ATCO Electric, in the compliance filing, to provide an update on the project's status and on the forecast capital expenditures, as required and to provide details regarding the work which is forecast to be completed in the test period. Depending on the information provided in the compliance filing, the Commission may adjust the approved project capital expenditures. ..... Paragraph 937

54. The Commission directs ATCO Electric to update its forecast capital expenditures and total project cost forecast in the compliance filing, to align with the PPS estimate for this project, while also accounting for the delay in the facility application proceeding. ..... Paragraph 949

55. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including changes to the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The new forecast start date for project 56767 is approximately one year later than initially estimated, and lower overall spending levels are anticipated once the project resumes. The Commission considers it reasonable to expect that the project may be delayed longer than one year, and, in any event, the continued economic weakness being experienced in Alberta may lead to a reassessment of the VREPTD as a whole. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove forecast capital expenditures associated with this project, for the purposes of determining revenue requirement, and to reflect the impacts of the removal in its compliance filing. ..... Paragraph 954

56. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including changes to the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The new forecast start date for project 56768 is approximately one year later than initially estimated, and lower overall spending levels are anticipated once the project resumes. The Commission considers it reasonable to expect that the project may be delayed longer than one year, and, in any event, the continued economic weakness being experienced in Alberta may lead to a reassessment of the VREPTD as a whole. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove forecast capital expenditures associated with this project, for the purposes of determining revenue requirement, and to reflect the impacts of the removal in its compliance filing. ..... Paragraph 959

57. The VREPTD program was deferred because of the deterioration in the state of Alberta's economy, including the expected load growth throughout the province as shown in the November 2015 AESO Long-Term Transmission Plan. The Commission expects that the continued economic downturn in Alberta may lead to a reassessment of the VREPTD as a whole. The New Drury and In/Out to Drury projects are a reflection of ATCO Electric's expectations of the changes to the VREPTD program and the upgrades which will be required in the area to provide system stability. The AESO, however, has not provided clear direction to ATCO Electric regarding the requirements and timing of projects in the area. Given the inherent uncertainty in the need and timing of projects within the VREPTD program, it is not reasonable to include these projects in the revenue requirement. ATCO Electric is directed to remove forecast capital expenditures in 2016 and 2017 for these projects, for the purposes of determining revenue requirement, in the compliance filing and to reflect the impacts of the removal in its compliance filing. ..... Paragraph 968

58. The Commission finds that given the current economic climate in Alberta, particularly the significant decline in the price of oil over the past two years, the uncertain future of the associated cogeneration facility and the fact that the customer has already placed this project on hold, it is very unlikely that this project will resume as forecast. Therefore, it is not reasonable to include costs for project completion in 2017. ATCO Electric is directed to remove 2017 capital expenditures and additions for Project 51181, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 979

59. The Commission also finds that, given the current economic climate in Alberta, particularly the significant decline in the price of oil over the past two years, and the early stage of the project, there is no indication that this project will proceed as forecast. Therefore, it is not reasonable to include this project in the revenue requirement. ATCO Electric is directed to remove forecast capital expenditures, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 990

60. The Commission finds there is insufficient information on the record to allow it to determine whether the forecast magnitude and timing of capital expenditures for the proposed project are reasonable. The record likewise provides no indication of the likelihood that the project will be undertaken at all. Based on the limited information available to it, and the apparent very early stage of the project, the Commission finds a more reasonable forecast expenditure level is one that reflects the preparation of a facility application, rather than the start of construction. ATCO Electric is directed to reduce Project 54020 capital expenditures in 2016 and 2017 to $0.2 million for each year in the compliance filing. ..... Paragraph 994

61. This project is currently in the very early stages of its execution. The Commission considers it unlikely that it will be completed in 2017. While the project schedule on the record shows that the project is delayed, there is no evidence to suggest that this project will not proceed during the test period. The Commission finds it reasonable to conclude that early project milestones, such as regulatory approvals, could be achieved in 2016, leading to the start of construction as early as 2017. ATCO Electric is directed to reduce Project 54156 capital expenditures in 2016 and 2017 by 90 per cent each year and to remove the forecast capital additions, for the purposes of determining revenue requirement, in the compliance filing. In the Commission's view, limiting costs to those associated with planning and preliminary engineering, regulatory, procurement and preliminary construction activities reflects a reasonable forecast for capital expenditures in the test period. It also accounts for delays in the schedule that suggest construction of this project is unlikely to begin until late 2017, with completion occurring in the next test period. ..... Paragraph 999

62. The Commission finds there is insufficient information on the record of this proceeding for it to approve the forecast costs for this project. Accordingly, the Commission directs ATCO Electric to reduce Project 55655 capital expenditures and additions in 2016 to $0 in the compliance filing. ..... Paragraph 1004

63. The Commission finds the following considerations raise significant doubts that this project will experience material, if any, progress during the test period: (1) the continued weakness in Alberta's economy including, especially, the reduced level of activity in Alberta's petroleum sector; (2) this project is still in its early stages; (3) the originally projected ISD has already been deferred by two years; and (4) the project's sole customer has frozen its capital expenditures. Therefore, it is not reasonable to include this project in approved capital expenditures. ATCO Electric is directed to remove the associated forecast capital expenditures for the purposes of determining revenue requirement in the compliance filing. ..... Paragraph 1011

64. The Commission finds that, with the Kent power plant not yet under construction and its economic and hydrogeologic feasibility still being assessed, it is not reasonable to forecast Project 56655 to be in-service by 2017. ATCO Electric is directed to remove forecast capital expenditures and additions for Project 56655, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1016

65. The VREPTD program was deferred and its scope was modified because of the downturn in Alberta's economy, as reflected in the November 2015 AESO Long-Term Transmission Plan. Given the uncertainty in the project schedule and the interdependence of ATCO Electric's scope of work with that to be completed by AltaLink, the Commission finds that it is not reasonable to include this project in ATCO Electric's approved revenue requirement. ATCO Electric is directed to remove the forecast capital expenditures and capital additions for Project 56865, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1021

66. The Commission finds that given the current economic climate in Alberta, low wholesale electricity market prices, lower than expected load growth, and the early stage of execution for this project, it is not reasonable to include this project in the utility's revenue requirement for the test years. ATCO Electric is directed to remove forecast capital expenditures for Project 58215, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1026

67. The Commission finds that given the economic climate in Alberta, low wholesale electricity market prices, lower than expected load growth, and the history of significant and recurring delays on projects 58562 and 58569, it is not reasonable to include capital expenditures for these projects in revenue requirement. Supporting the Commission's conclusion is the fact that no update has been provided by ATCO Electric to an August 2015 progress report in respect of Project 58569, which stated that "[t]he project is currently on hold and the milestone schedule forecast will be updated once customer funding is received which impacts the project schedule." ATCO Electric is directed to remove forecast capital expenditures for both projects, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1034

68. Construction of the Keystone XL pipeline is the key driver for projects 58923, 58924 and 58925. Given the current status of the proposed pipeline and ATCO Electric's forecast suspension of all spending on these projects in 2015, it is not reasonable to include forecast expenditures resuming in 2016 and 2017. ATCO Electric is directed to remove projects 58923, 58924 and 58925 from its forecast capital expenditures, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1043

69. The Commission finds that various factors affect the reasonableness of the forecast ISD in the business case for this project. Alberta is currently facing a challenging economic climate that is made all the more uncertain by a sustained period of low oil prices. The Commission finds that given these factors, it is not reasonable to include this project in the utility's revenue requirement for the test years. ATCO Electric is directed to reduce Project 58965 capital expenditures in 2016 and 2017 to $0.2 million and remove the forecast capital additions, for the purposes of determining revenue requirement, in the compliance filing. ..... Paragraph 1048

70. For the reasons set out above, the Commission is not persuaded of the reasonableness of the forecast capital maintenance costs and is prepared to approve only a reduced level of expenditures for revenue requirement purposes. The Commission considers that the size of the required reduction is reasonably informed by both the nature of the shortcomings identified in the currently proposed forecasts and observed historical variances from previously approved forecasts. The Commission finds that both the observed two-year average variance from forecast of approximately 33 per cent and five-year average variance of 22.6 per cent are directionally consistent with the application of a 25 per cent reduction to the submitted forecasts. The Commission notes, in this regard, that its

selection of a five-year period accords with the period of historical averages used by the Commission to test forecasts. The Commission directs ATCO Electric to apply this 25 per cent reduction to the capital maintenance and isolated generation forecasts (as provided in ATCO Electric's Schedule 10-4) after making adjustments for the Double Circuit project and the relocation projects, the latter being covered by customer contributions. Any adjustments related to directions elsewhere in this decision which affect TCM or isolated generation forecasts (such as the inflation factors addressed in sections 5.2.1 and 5.3) shall be made in the compliance filing in addition to the directed reductions. The Commission directs ATCO Electric to provide the revised TCM breakdown in its compliance filing. ..... Paragraph 1100

71. Given the lack of business case support provided by the utility in its application, the Commission is not prepared to approve any of the expenditures forecast for the double circuit project in the test period and directs ATCO Electric to remove the expenditures from its current forecast. ATCO Electric is directed to submit a business case with the requested level of detail in its next GTA. ..... Paragraph 1112

72. The Commission finds that the forecast capital expenditure increases for Project 90130 in 2016 and 2017 to refurbish/replace engines and turbines are not justified. They represent increases of more than 100 per cent over 2015 levels. The submitted business case confirmed that fewer life-extending activities and replacements would be occurring in 2016 and 2017 than in 2015. The Commission accepts that the number of activities alone is not a sufficient indicator of the reasonableness of the overall forecast, however, in this case, the work proposed for completion in each of 2015 and 2017 is very similar. For example, three of the life extension projects are identical in terms of location, unit type, and proposed work. Similarly, the proposed customer-funded life extensions are both overhauls of natural gas units at the same location, with work on a larger unit forecast to occur in 2017. Other work identified in the business plan includes a 2015 forecast for a major overhaul on a 1,000 kilowatt (kW) unit and replacement of a 25-kW unit, a 50-kW unit and a mobile unit, while the 2017 forecast is for the replacement of a single 140-kW unit. The Commission is not persuaded that this difference alone justifies the observed increase in forecast capital expenditures from $1.4 million to $3.0 million. ATCO Electric is directed to revise the Project 90130 forecast costs for 2016 and 2017 to 2015 levels. ..... Paragraph 1127

73. Given ATCO Electric's description of asset management in the business case for project 82660 and how it should integrate with MAXIMO, CROW, Oracle, MOPS and GIS information systems, the Commission is of the view that a comprehensive business case treating all these components as a single project is required. This business case should itemize all the work required, including any necessary enhancements or upgrades to the various IT systems on an historical and go-forward basis. This business case should also provide a cost/benefit analysis with a clear description of future cost requirements including as much of the life cycle as can reasonably be anticipated. ATCO Electric is directed to provide such a business case in its next GTA. ..... Paragraph 1156

74. For purposes of determining the opening rate base in 2015, 2014 additions totalling $4.0 million related to asset management are disallowed. Forecast expenditures in all test years related to asset management totaling $3.9 million are also to be removed in addition to related O&M expenses totaling $2.1 million. ATCO Electric is directed to make these adjustments in its compliance filing. ..... Paragraph 1158

75. The Commission finds that when ATCO Electric updated the application and costs for Project 82690 it also should have submitted a business case because the forecast costs for this project increased to more than $500,000. There is no basis to justify, in the public interest, the forecast for the project when the available information, namely a cost and project title, is insufficient to determine what the project is or why it is needed. Prior to arriving at its determination with respect to this project, the Commission considered the following four options: (1) deny all costs, (2) approve only the original cost forecast of $0.4 million, (3) approve up to the business case requirement threshold of $499,999, or (4) direct ATCO Electric to file a business case in the compliance filing. The Commission finds that the creation of a business case is a basic, uncomplicated function, and one that should have been undertaken for Project 82690 when the cost forecast doubled, if only as part of an exercise to consider why the costs doubled and to assess whether the project is still feasible and needed at the new cost level. Costs for Project 82690 are denied. ATCO Electric is directed to remove this project cost in the compliance filing. ..... Paragraph 1167

76. The Commission's general views with respect to ATCO Electric's submitted business cases are discussed in Section 11.1.5. The business case for projects 82582, 82585 and 82689, Enterprise Technology Infrastructure Enhancements, was found particularly lacking given that it was forecast to be one of the larger IT capital projects with costs forecast at $2.5 million for the 2015-2017 test period. The forecast costs for this business case account for approximately 15 per cent of the software project spending over the test period. The shortcomings of the business case are reflected in the vague description of potential benefits, a single alternative considered (which was to do nothing), and a forecast methodology and assumption section containing the solitary statement that "[t]he OCIO and IT service provider collaborated to produce the estimates for these initiatives." The forecast methods and assumptions description is the weakest of the submitted software business cases. The business case does not sufficiently address why the status quo is not a viable alternative when the identified mitigations for key risks of not implementing the projects appeared to suggest that acceptable mitigations were available. The Commission finds that the overall deficiencies in this business case result in insufficient evidence to support the project. Forecast costs for projects 82582, 82585, and 82689 are denied. ATCO Electric is directed to remove these project costs in the compliance filing. ..... Paragraph 1168

77. The Commission notes that ATCO Electric has stated that it expects to reduce forecast costs for Project 84000 by $9.0 million in the compliance filing. The Commission directs ATCO Electric to reflect this reduction in the compliance filing, as proposed. .. Paragraph 1178

78. The Commission directs ATCO Electric to update the net salvage credits in Schedule 10-4 in the compliance filing to account for impacts arising from Commission directions elsewhere in the decision. ..... Paragraph 1188

79. The Commission directs ATCO Electric, in the compliance filing, to provide a list of the 2015 and 2016 actual contribution amounts received, by project, and when any contribution that has been received was paid to ATCO Electric by the customer(s). ATCO Electric is also directed to update the CIAC in Schedule 10-8 to align with Commission directions in Section 11.4.1 of this decision. ..... Paragraph 1193

80. The forecast for total ES&G costs in the test period may be affected by other directions included in this decision, as will the resulting ES&G rate. The Commission directs

ATCO Electric, in the compliance filing, to update the total forecast ES&G costs and rates for the test period, as necessary, to reflect all applicable directions included in this decision. ..... Paragraph 1206

81. The Commission's determinations on the level of net depreciation are found in Section 8 of this decision. The Commission directs ATCO Electric, in the compliance filing, to reflect all findings and determinations which affect the net depreciation used in the necessary working capital calculations. ..... Paragraph 1123

82. The Commission's determinations on the level of operating expenses are found in Section 7 of this decision. The Commission directs ATCO Electric, in the compliance filing, to reflect all findings and determinations which affect the operating expenses used in the necessary working capital calculations. ..... Paragraph 1225

83. In the application, ATCO Electric stated that the "Affiliate Cost of Goods Sold is offset by Affiliate Revenues and will have no material impact on revenue requirement." The Commission considers that on a forecast basis the affiliate revenues may offset the affiliate cost of goods sold included as transmission expense. However, including these affiliate costs in the calculation of the operating expense component of necessary working capital does affect the necessary working capital calculation for operating expense and, therefore, also affects revenue requirement through its inclusion in rate base. The Commission, therefore, directs ATCO Electric, in the compliance filing, to reduce the total fuel & operating costs used in the necessary working capital calculation for operating expense by the total affiliate cost of goods sold for each of the test years. The Commission will not, however, reduce the amount of the operating expense adjustment by the affiliate cost of goods sold overhead recovery shown in Table 55 above because it represents a separate recovery of overhead costs which are less direct in nature. This amount will therefore remain as a reduction to the operating expense total used for the calculation to ensure affiliate related overhead costs are not included in the revenue requirement. ..... Paragraph 1227

84. For the above reasons, the Commission directs ATCO Electric to prepare and file an updated comprehensive lead/lag study as part of its next GTA application. ..... Paragraph 1231

85. The Commission finds that the forecast increases in A&G costs are, on the whole, unusually large. The Commission finds that the provided forecasts do not lie within a reasonable range and that the methodology used to generate them is likewise unreasonable. The Commission accepts the RPG's recommended reductions in each test year of $2 million, $1.2 million and $0.3 million for USA accounts 920, 923 and 930.2, respectively. In addition, the Commission expects ATCO Electric to apply the same global percentage reductions to corporate A&G expenses as may be applied to operating expenses as determined elsewhere in this decision. The Commission directs ATCO Electric to provide all changes as noted, in its compliance filing. ..... Paragraph 1249

86. Although ATCO Electric has acknowledged that its proposal deviates from the methodology approved in Decision 2013-358, it has provided no reasons to justify it. ATCO Electric did not describe any benefits of its proposal nor demonstrate why it is reasonable. It likewise provided no comparison of results that would flow from its preferred approach relative to the approved method. For these reasons, the Commission declines to approve the method proposed and directs ATCO Electric to use the audited

financial data from 2013 to determine the allocation factors for all three test years. ..... Paragraph 1275

87. The Commission observes that in Exhibit 20272-X0758 ATCO Electric provided a response to an IR by setting out dollar amounts. The Commission directs ATCO Electric to provide, in the compliance filing, the volume amounts that were used to calculate the dollar values, an explanation of which category of volumes was adjusted, and the final volume amount for each test year. ATCO Electric is also directed to provide an update to Exhibit 20272-X0721, AET-CAL-2015DEC30-004(h) Attachment 1, and Exhibit 20272-X0722, AET-CAL-2015DEC30-006(a) Attachment 1 if required to comply with the above directive. ..... Paragraph 1284

88. ATCO Electric is directed, starting January 1, 2017, to (1) resume normal regulatory AFUDC accounting for direct assigned capital, (2) discontinue CWIP in rate base for direct assigned projects, and (3) discontinue recovering the capital portion of pension costs on a cash basis, and instead return to collection of the capital portion of pension expense as part of invested capital. ATCO Electric is directed to reflect this in the compliance filing. ..... Paragraph 1310

89. 1311....ATCO Electric is further directed to propose a method, in the compliance filing to refund the accumulated difference resulting from the change in accounting treatment of capital pension costs, including related income tax impacts. Supporting schedules shall be provided for calculations of all adjustment amounts proposed, along with identification of all assumptions made. ..... Paragraph 1311

90. The Commission has made its determinations on the level of depreciation expenses in Section 8 of this decision. Determinations made in other sections of this decision may also have impacts on the calculation of credit metrics. The Commission directs ATCO Electric, in the compliance filing, to reflect all findings and determinations included in this decision which affect the credit metrics measures. ATCO Electric is directed to provide updated credit metric ratios by year as displayed in Table 59 above. ..... Paragraph 1312

91. The Commission considers that a deferral account for debt cost rates should only be used for 2016 and 2017. The Commission directs that actual debt cost rates be used for 2015. ..... Paragraph 1334

92. Having approved the use of a deferral account for debt costs over the last two years of the test period, the Commission is also required to determine a reasonable forecast for the cost of debt in each of the test years. The actual cost of debt for ATCO Electric's 2015 debt issuances is known. For this reason, the Commission directs ATCO Electric, in the compliance filing, to update its application in all aspects to reflect the 2015 actual cost of debt resulting from the actual 2015 long-term debt issues. The Commission finds that, overall, the forecasting method employed by ATCO Electric in respect of 2016 and 2017 debt cost rates is reasonable. On balance, it is not persuaded that the adoption of the methodology proposed by the CCA, which incorporates weighted averages of both consensus forecast and Bloomberg forward curve data, will result in a significant reduction of forecast risk, especially since this cost will be afforded deferral account treatment. ..... Paragraph 1336

93. The Commission notes that ATCO Electric provided conflicting debt cost rate forecasts for 2016 and 2017 based on information it filed on the same day. The Commission approves ATCO Electric's forecast debt cost rates of 4.3 per cent and 4.8 per cent for

each of 2016 and 2017, respectively. The Commission considers these cost rates to be reasonable based on a comparison to the recent actual experience for 2015 being in the 4.0 per cent to 4.2 per cent debt cost range and, based on its approval of deferral account treatment for use in each of 2016 and 2017. The Commission directs ATCO Electric, in the compliance filing, to update its application in all aspects to reflect the forecast long-term debt cost rates of 4.3 per cent and 4.8 per cent for 2016 and 2017, respectively. ..... Paragraph 1337

94. ATCO Electric is directed to revise the affiliate cost of goods sold overhead recovery shown on Schedule 5-3 (transmission expense) and Schedule 25-3 (corporate expense) to ensure that the level of overhead costs included in the affiliate cost of goods sold, namely 70 per cent of labour for construction projects, is also reflected in the overhead recovery. By correcting this error, the overhead amount included in the cost of providing services to WFMAC will match the overhead recovery amount, resulting in no net impact on ratepayers. ..... Paragraph 1367

95. ATCO Electric is further directed to review and adjust all other items included in affiliate cost of goods sold and ensure that the overhead recovery included in the total is then offset using the same amount of overhead recovered as is recorded on Schedule 5-3 for transmission expense or Schedule 25-3 for corporate expense. As part of the compliance filing, ATCO Electric is directed to provide a schedule setting out the results of its review and all consequential adjustments arising therefrom. ..... Paragraph 1368

96. For these reasons, the Commission directs ATCO Electric to provide information in the nature of that shown in tables 64 and 65, above, on costs and revenue offsets, along with detailed explanations for any differences between annual forecasts and actuals, as well as any differences in actuals between costs and revenue offsets for the year being compared. This information shall be provided as separate schedules along with the annual compliance report filed with the Commission. ..... Paragraph 1371

97. For these reasons, the Commission is not persuaded that the RPG's request is reasonable in the circumstances. However, it directs ATCO Electric to provide the following information as part of all future GTA proceedings:

- Complete descriptions of all sales or transfers of ATCO Electric transmission assets occurring in the period covering actual information filed for comparison use to the test years. Information regarding identified transactions must include a description of the assets involved, a statement of the transaction value including confirmation of whether and (if applicable) how fair market value pricing was determined (including copies of all valuation reports relied upon).

- Identification of all asset transactions between ATCO Electric and an affiliate, for each comparison year of actuals or any portion thereof. For example, in the current 2015-2017 proceeding, 2012 through 2014 actuals were provided for comparative purposes. In addition, the 2015 test year forecast included a portion of 2015 YTD actuals. For this example, information should be provided for 2012 through 2015 YTD actuals. ..... Paragraph 1385

98. The Commission advises that approvals granted in relation to certain aspects of ATCO Electric's application may have impacts on amounts to be recorded in other areas (e.g., operating costs and no cost capital) despite the fact that they have not been expressly addressed in this decision. Consequently, ATCO Electric is directed to update its

compliance filing for all impacts on all matters comprising its application for the test years regardless of whether they are expressly addressed herein. ..... Paragraph 1388

Decision 26573-D01-2023

AUC
Alberta Utilities Commission

ATCO Electric Ltd.

Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances

April 26, 2023

Alberta Utilities Commission
Decision 26573-D01-2023
ATCO Electric Ltd.
Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances
Proceeding 26573

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The Commission may, no later than 60 days from the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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Alberta Utilities Commission
Calgary, Alberta

ATCO Electric Ltd.
Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances

Decision 26573-D01-2023
Proceeding 26573

1 Decision summary

1. This decision sets out the determinations of the Alberta Utilities Commission on an application filed by ATCO Electric Ltd. for its 2018-2021 transmission direct assigned capital deferral accounts and annual filing for adjustment balances (DACDA application). In its application, ATCO Electric requested approval of a one-time net refund to the AESO of $11.3 million (i.e., a refund to Alberta electricity customers of $11.3 million).

2. The Commission has decided to disallow the recovery of the following amounts which will increase the total amount of the refund:

(i) $4.381 million of forgone return on rate base related to its treatment of customer contributions

(ii) $3.0 million related to ATCO Electric's imprudent management and execution of the Jasper Transmission Interconnection Project (Jasper project);

(iii) A further 20 per cent reduction for amounts imprudently incurred connected with ATCO Electric's engagement of Backwoods Contracting Ltd. (Backwoods) on the Jasper project;[1] and

(iv) $0.250 million for work conducted in an effort to mislead and conceal information associated with ATCO Electric's decision to engage Backwoods on the Jasper project.

The Commission has directed that ATCO Electric reflect these disallowances in a future compliance filing. The disallowed amounts will not be recoverable from Alberta electricity customers.

2 Introduction

3. ATCO Electric is a transmission facility owner (TFO) that provides regulated electric transmission service in Alberta. ATCO Electric recovers the costs of providing electric transmission service through its transmission tariff, which must be approved by the Commission. Once approved, ATCO Electric recovers its tariff amounts from the Alberta Electric System Operator (AESO), which collects the costs of transmission services provided to Alberta electricity customers through their respective distribution facility owners, and from customers directly connected to the transmission system.

[1] The Commission estimates this further reduction to be approximately $2.2 million based on ATCO Electric's applied-for amount. The exact dollar impact of this disallowance will be determined in ATCO Electric's compliance filing to this decision.

4. As with all DACDA applications, this application is an after-the-fact assessment of the prudence of the costs incurred by ATCO Electric, where final costs are established by reconciling and disposing of a number of deferral account balances.[2] This includes deferral accounts that record costs incurred by ATCO Electric to construct transmission projects undertaken in response to mandatory directions received from the AESO. ATCO Electric's forecast capital costs for these projects were already approved by the Commission in prior regulatory proceedings. If there is a difference between ATCO Electric's forecast capital costs and the actual capital costs incurred, then, subject to the Commission's review and approval, any difference between the amount that ATCO Electric has been paid by the AESO and the amount that ATCO Electric should have been paid by the AESO is either paid to, or recovered from, ATCO Electric, as required. When examining ATCO Electric's application, the Commission assesses the prudency of ATCO Electric's actual capital costs incurred. ATCO Electric is allowed to recover capital costs through its tariff only if the Commission determines that the actual capital costs were prudently incurred.

5. In Decision 2001-110[3] the Commission previously articulated the test for prudence as follows:

> In summary, a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take into account the best interests of its customers, while still being entitled to a fair return.

6. The Commission has applied this test in determining whether the applied-for costs in ATCO Electric's DACDA application were prudently incurred.

7. ATCO Electric originally requested approval to refund $7 million for deferral accounts covering the 2018-2020 timeframe and to collect $3.5 million for annual filing adjustments, resulting in a request for Commission approval of a one-time net refund to the AESO of $3.4 million.[4]

8. ATCO Electric amended its original application in response to Commission directions, discussed in greater detail in the following sections of this decision. ATCO Electric's amended application included its 2021 DACDA application and removed $10.8 million of above fair market value costs related to the Jasper project. In the amended application ATCO Electric requested approval of a refund of $13.9 million for deferral accounts covering the 2018-2021 timeframe (including a refund of $1.9 million associated with ATCO Electric's direct assigned capital deferral account and a $12.0 million refund for other deferral account adjustments) and a collection of $2.6 million for annual adjustments related to cancelled projects. The net result is a request for a one-time net refund to the AESO of $11.3 million (i.e., a refund to Albertans of $11.3 million).

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[2] For example: right-of-way payments, property taxes and long-term debt rates as noted in Table 1 below.

[3] Decision 2001-110: Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding, Part B-1: Deferred Gas Account Reconciliation for ATCO Gas, December 13, 2001. This articulation of the prudence test was also cited in decisions 24681-D01-2020 and 3585-D03-2016.

[4] Totals do not reconcile due to rounding.

9. The Commission has reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered.

10. This decision addresses the contentious cost items included in the application, including application updates, and any matters that the Commission has otherwise determined are required to be specifically addressed. If a matter is not specifically addressed in this decision, it is because the Commission finds the applied-for costs associated with the matter to be reasonable and the applicant's request is therefore approved as filed. All directions in this decision are subject to all findings and other directions made elsewhere in this decision.

11. The Commission requires ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before May 29, 2023; provided, however, that ATCO Electric is not required to submit such a compliance filing if the Commission orders a compliance filing for ATCO Electric's 2023-2025 general tariff application in Proceeding 27062. In such a case, the Commission directs ATCO Electric to incorporate the findings, conclusions and directions of the Commission in this decision together with its compliance filing to the Commission's decision in Proceeding 27062.

3 Background to the application process

12. On June 9, 2021, ATCO Electric filed its 2018-2020 DACDA application. The Commission considered the 2018-2020 DACDA application in Proceeding 26573 through a hearing process that was expected to culminate in oral argument on September 29, 2021.

13. On October 6, 2021, after oral argument, ATCO Electric requested that the Commission stay the release of its decision on the 2018-2020 DACDA account application. ATCO Electric indicated that a matter was subject to an ongoing internal investigation by its corporate security and also by AUC Enforcement staff.[5] ATCO Electric indicated that the amounts it was seeking to recover in the application may change, pending the outcome of these investigations. AUC Enforcement staff subsequently informed the Commission that it supported ATCO Electric's request for a stay.

14. In a letter dated October 7, 2021, the Commission granted ATCO Electric's stay request.[6]

15. Suspension of the Commission's consideration of the 2018-2020 DACDA application was necessary because AUC Enforcement staff commenced an investigation, pursuant to sections 8 and 63 of the *Alberta Utilities Commission Act*, asserting that ATCO Electric contravened various regulatory instruments in procuring access matting, brushing/clearing and hydrovac services for the Jasper project (access services).[7] Amounts related to the Jasper project were included in ATCO Electric's DACDA application for 2018-2020. The investigation by

[5] Exhibit 26573-X0286, AET Letter Requesting Interim Stay of the AUC's Decision.
[6] Exhibit 26573-X0288, AUC letter - ATCO Electric request to suspend release of the decision, PDF page 1, paragraphs 1-4.
[7] Proceeding 27013, Exhibit 27013-X0034, Application of Enforcement Staff re ATCO Electric, PDF pages 4-5, paragraphs 1-7.

AUC Enforcement staff resulted in the commencement of an enforcement proceeding, Proceeding 27013.[8]

16. On April 14, 2022, AUC Enforcement staff and ATCO Electric entered into a settlement agreement on the alleged contraventions that had been the subject of AUC Enforcement staff's investigation and filed the agreement for Commission approval.[9] Included in the settlement agreement was a request asking the Commission to issue an order, requiring ATCO Electric to pay an administrative penalty in the amount of $31.0 million made out to the General Revenue Fund of Alberta.[10]

17. On June 29, 2022, the Commission approved the settlement agreement in Decision 27013-D01-2022 and ordered, among other things, ATCO Electric to pay an administrative penalty of $31.0 million.[11] In that decision, the Commission made findings which included the following:[12]

(i) ATCO Electric knowingly sole-sourced access services for the Jasper project to Backwoods at rates above fair market value, to the benefit of its unregulated affiliate, ATCO Structures and Logistics Ltd.[13]

(ii) Backwoods subcontracted most, if not all, of the matting-related work on the Jasper project to another contractor.[14]

(iii) ATCO Electric created a misleading paper trail justifying its decision and concealing critical information about why it sole-sourced the contract – namely, to benefit ATCO Structures and Logistics Ltd. – in an attempt to avoid Commission detection of its actions and improperly recover those above fair market costs from Alberta electricity customers.[15]

(iv) ATCO Electric estimated that approximately $10.8 million of the access services costs it incurred for the Jasper project were attributable to the above-market rates that it paid to Backwoods (costs associated with the sole-source Backwoods contract).[16]

18. In addition, under the settlement agreement, ATCO Electric agreed to amend its 2018-2020 DACDA application to reflect revised applied-for access services costs for the Jasper project.[17] The settlement agreement also stated that the quantum of any amounts associated with

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[8] AUC Enforcement staff are responsible for investigating complaints and contraventions of AUC rules, orders and decisions, and making recommendations to the AUC on whether to commence enforcement action for alleged contraventions. Protocols regarding the segregation of Enforcement staff and adjudicative personnel are outlined in AUC bulletins 2014-05, Alberta Utilities Commission enforcement policy, and 2016-10, Practices regarding enforcement proceedings and amendments to AUC Rule 001: Rules of Practice.

[9] Proceeding 27013, Exhibit 27013-X0069, Settlement Agreement and Agreed Statement of Facts.

[10] Proceeding 27013, Exhibit 27013-X0069, Settlement Agreement and Agreed Statement of Facts, PDF page 6.

[11] Decision 27013-D01-2022: Enforcement Staff of the Alberta Utilities Commission, Allegations against ATCO Electric Ltd., Proceeding 27013, June 29, 2022.

[12] These findings are the most relevant to this proceeding, and they are not a comprehensive list of the Commission's findings from this decision.

[13] Decision 27013-D01-2022, PDF pages 4, 9 and 18, paragraphs 2, 27-28 and 70-71.

[14] Decision 27013-D01-2022, PDF pages 9-10, paragraphs 30-31.

[15] Decision 27013-D01-2022, PDF page 4, paragraph 2.

[16] Decision 27013-D01-2022, PDF page 8, paragraph 24.

[17] Proceeding 27013, Exhibit 27013-X0069, PDF pages 6-7, paragraph 12.

ATCO Electric's misconduct related to the procurement of access services for the Jasper project may be assessed and tested by the Commission panel presiding over the 2018-2020 DACDA application in Proceeding 26573.[18]

19. In approving that settlement agreement, the Commission indicated that:

> ATCO Electric must amend its deferral account application to remove any costs incurred for the Jasper project that are above fair market value, and this will be considered by the Commission panel assigned to the deferral account proceeding. That panel will determine what the fair market value of the work is, based on the evidence of all the parties participating in the deferral account proceeding.[19]

20. On July 13, 2022, the Commission issued a letter[20] notifying parties that it was reopening Proceeding 26573. In that letter, the Commission directed ATCO Electric:

(i) to file a comprehensive update to the information that it originally filed in support of the Jasper project;

(ii) to file exhibits from Proceeding 27013 that contain relevant cost information on access services for the Jasper project; and

(iii) to refile its 2021 DACDA application (which had been filed in Proceeding 27062) on the record of Proceeding 26573, because the Commission found that it would be more efficient to consider the settlement of ATCO Electric's 2021 deferral balances in Proceeding 26573.

21. On August 11, 2022, ATCO Electric amended its 2018-2020 DACDA application and refiled its 2021 DACDA application on the record of Proceeding 26573.[21] ATCO Electric removed $10.8 million associated with the sole-source Backwoods contract from its requested cost recovery, and provided information outlining the assumptions and calculations that it used to derive the $10.8 million reduction.

22. On September 20, 2022, the Commission filed a letter[22] advising parties that further testing of ATCO Electric's 2018-2020 DACDA application would be limited to matters that were both relevant to a DACDA application proceeding (i.e., what costs should be included in customer rates), and were affected by the new information that was disclosed in the enforcement proceeding. The Commission also emphasized that this would not be an opportunity to retest matters that were not relevant to the new information that was disclosed.

23. The Commission did not assess the $31.0 million administrative penalty in this proceeding, because it was already adjudicated in the enforcement proceeding, and was not a matter that is relevant to a DACDA application.

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18 Proceeding 27013, Exhibit 27013-X0069, PDF page 36, paragraph 144 and footnote 2.
19 Decision 27013-D01-2022, PDF page 22, paragraph 90.
20 Exhibit 26573-X0291, AUC letter - Reopening of Proceeding 26573 and ATCO Electric's application amendment.
21 Exhibit 26573-X0295, Cover Letter enclosing AET Amended 2018-2021 Deferral Application.
22 Exhibit 26573-X0332, AUC letter - Scope of Proceeding 26573 and process schedule.

24. The Commission closed the record for the proceeding on January 26, 2023, when oral reply argument for the application was completed.[23]

4 ATCO Electric 2018-2021 DACDA

25. ATCO Electric requested the following adjustments as reflected in Table 1-1 of the application:

Table 1. Summary of deferral accounts and annual adjustments amount/(refund to)

	2018	2019	2020	2021	2022	Total
Deferral accounts	($000)					
Direct Assigned Capital	(1,661)	3,102	256	(2,538)	(1,056)	(1,897)
Deducting Deferral	564	356	190	161	99	1,299
Capital Repairs	29	(879)	391	(886)	-	(1,344)
ROW [right-of-way] Payments	48	(543)	(22)	(78)	-	(596)
Property Tax	(2,415)	(5,445)	(1,948)	(1,472)	-	(11,282)
Long-Term Debt Rates	-	(114)	-	-	-	(114)
Total deferral accounts	(3,434)	(3,523)	(1,214)	(4,813)	(956)	(13,934)
Annual filing for adjustments						
Cancelled projects	(244)	3,239	522	(931)	-	2,585
Total annual adjustments	(244)	3,239	522	(931)	-	2,585
Total (refund) / collection	(3,678)	(284)	(691)	(5,745)	(956)	(11,349)

Source: Prepared from Exhibit 26573-X0006.01, AET 2018-2020 Deferral Application, Table 1-1: Summary of Deferral Accounts and Annual Adjustments, PDF page 4.

26. The remainder of this decision addresses each of the issues remaining to be resolved, and any related issues that arise under them.

5 Issue 1: Has ATCO Electric complied with previous Commission directions?

5.1 Decision 24375-D01-2020 (directions 5, 7 and 12) and Decision 22393-D02-2019 (Direction 3)

27. In its application, ATCO Electric responded to three outstanding directions (directions 5, 7 and 12) from Decision 24375-D01-2020[24] in respect of ATCO Electric's Transmission Application for Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances. Copies of these directions have been provided in Appendix 4 of this decision.

28. With respect to Direction 5 allowing ATCO Electric to true up the recovery of certain foundation materials costs for project 55127 in full,[25] the Commission finds that ATCO Electric has complied and that no further action by ATCO Electric is required. In the current application,

[23] This oral argument and oral reply argument process was limited to the amendments that ATCO Electric made on and after August 11, 2022, and matters that were both relevant to a DACDA application and were affected by the new information that was disclosed in the enforcement proceeding.

[24] Decision 24375-D01-2020: ATCO Electric Ltd., Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 24375, November 30, 2020.

[25] Exhibit 26573-X0006.01, application, paragraph 21, and Table 2.6-1, PDF pages 11 and 33.

the costs at issue result in offset amounts because of the redeployment of cancelled project material costs for which ATCO Electric had received funding in Decision 24375-D01-2020. Further details respecting this and a similar project are discussed in Section 6 of this decision.

29. With respect to Direction 7 requiring ATCO Electric to ensure air travel costs are charged at no more than commercial airlines economy fare, ATCO Electric stated that an applicable adjustment had not been incorporated into its application on the basis that the amount at issue is immaterial.[26] The Commission finds that ATCO Electric has not complied with this direction. The Commission further directs ATCO Electric to reduce its applied-for costs by $11,267 in its compliance filing to this decision.

30. With respect to Direction 12 requiring ATCO Electric to provide documentation explaining its processes related to determining when external legal resources are required,[27] the Commission finds that ATCO Electric complied with this direction and no further action by ATCO Electric is required. The Commission does not accept the Consumers' Coalition of Alberta's (CCA) evidence[28] pertaining to this direction or the CCA's evidence recommending that a further disallowance for legal costs incurred for the Jasper project for partners and associates costs is required. The Commission has found that the hourly rate data used by the CCA was outdated and did not provide a reliable point of comparison for the reductions proposed by the CCA.

31. The Commission also examined ATCO Electric's ongoing compliance with Direction 3 of Decision 22393-D02-2019[29] pertaining to travel time for its legal counsel. The Commission directed ATCO Electric to charge legal counsel travel time at 50 per cent of the hourly rate, rather than the 100 per cent rate used by ATCO Electric in the current application. The Commission accepts ATCO Electric's statement that it will apply a reduction of $12,144[30] to the amounts requested in its compliance filing to this decision to comply with this direction.[31] Doing so will result in ATCO Electric compliance with the Commission's findings in Decision 22393-D02-2019.

32. The Commission notes that non-compliance by ATCO Electric with Direction 7 of Decision 24375-D01-2020 and Direction 3 of Decision 22393-D02-2019, led to these matters being subject to dispute in this proceeding, which was precisely the outcome the Commission sought to avoid in issuing the directions in the first instance. It also led to the unnecessary use of parties' time and resources in their efforts to clarify the record. These outcomes are inconsistent with regulatory efficiency and further, raise concerns with ATCO Electric's ability to comply with Commission directions, and its culture of compliance, without the need for greater regulatory oversight.

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[26] Exhibit 26573-X0006.01, application, PDF pages 12-13, paragraphs 22-23.
[27] Exhibit 26573-X0006.01, application, PDF pages 13-21, paragraphs 24-46.
[28] Exhibit 26573-X0248, CCA Evidence on Jasper including Legal Costs
[29] Decision 22393-D02-2019: ATCO Electric Ltd., Hanna Region Transmission Development Deferral Account, Proceeding 22393, June 6, 2019.
[30] Exhibit 26573-X0261, AET-AUC-2017SEP17-001(b), PDF page 4.
[31] Transcript, Volume 1 (September 29, 2021), page 28, line 25 to page 29, line 6.

5.2 Ongoing directions

33. ATCO Electric also referred, in the current application, to its continued compliance with earlier Commission directions that addressed the nature and required level of detailed information necessary to support ATCO Electric's DACDA applications.

34. Having reviewed the information provided by ATCO Electric,[32] the Commission confirms that ATCO Electric is in compliance with the following decisions and directions:

- Decision 21206-D01-2017 (directions 11 and 12)[33]
- Decision 2013-358 (Direction 92)[34]
- Decision 2014-283 (directions 1, 2, 3, 4 and 21)[35]

6 Issue 2: Are ATCO Electric's cancelled project costs reasonable?

35. In this section, the Commission examines ATCO Electric's request to recover costs for three categories of cancelled direct assigned projects:[36] cancelled system projects, cancelled customer projects and cancelled "other projects."

36. System projects are generally those facilities constructed for the benefit of all users of Alberta's transmission system.

37. Customer projects are initiated by a market participant (or customer) to facilitate the construction of, and that customer's connection to, a transmission facility (a transmission connection facility). The customer funds the project, that is built for its own benefit and use, by making a customer contribution to the TFO that is responsible for Alberta's transmission system where the customer project is located. The costs incurred by the TFO to construct the customer project are offset by the customer contribution.

38. "Other projects" is a category applied to direct assigned projects that are cancelled, and expenditures incurred up to the point of project cancellation are redeployed to a new direct assigned project. In such circumstances, there is a refund (or offset) of costs for the cancelled project that is recognized.

39. In Section 2.6 of its application, ATCO Electric outlined its proposal to recover the net costs associated with the three categories of cancelled direct assigned projects. It asked to recover: $0.066 million arising from the cancellation of one system project; $4.381 million related to the cancellation of 14 customer projects and a $1.796 million refund (or offset) of costs related to "other projects" and other adjustments discussed in Decision 24375-D01-2020.

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32 Exhibit 26573-X0006.01, application, PDF pages 21-25, paragraphs 47-53.
33 Decision 21206-D01-2017: ATCO Electric Ltd., 2013 and 2014 Transmission Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 21206, September 20, 2017.
34 Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Proceeding 1989, Application 1608610, September 24, 2013.
35 Decision 2014-283: ATCO Electric Ltd., 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances, Proceeding 2683, Application 1609720, October 2, 2014.
36 Direct assigned capital projects are transmission facility proposals that the AESO has directed a TFO, in this case ATCO Electric, to submit for Commission approval to meet the need identified in the AESO's needs identification document (NID).

Accordingly, its requested recovery of costs for cancelled direct assigned projects during 2018-2021 was a net amount of $2.585 million, as shown in Table 2 below:

Table 2. Summary of 2018-2021 cancelled direct assigned project costs

AET appropriation number	AET project name/description	Cost to be recovered/(refunded) ($ million)
56772	Nevis Transformer	0.066
Total system projects		0.066
51162	Blumenort – Windy Hills 144kv [kilovolt]Transmission Line	0.348
56820	Halkirk II Wind Power Facility	0.195
51181	Three Creeks Power Plant	2.973
56878	SAGD Foster Creek DTS Cap Upgrade	0.031
58526	Oyen Wind Power Project	0.154
58562	Hand Hills Wind Power Project	0.185
58569	Hand Hills Wind Power Facility	0.164
56865	Wainwright	0.045
58572	Hand Hills Wind Project Phase II	0.031
58573	Hand Hills Solar	0.033
51090	ATCO Power Rainbow Lake Gas (2021)	0.028
55605	Kineticor Peace Hills Power Line Tap (2021)	0.091
58525	Oyen Wind Energy Project (2021)	0.023
58574	Forestburg Area Solar (2021)	0.014
Total cancelled customer projects[37]		4.381
55127	Decision 24375-D01-2020, paragraph 77	(0.100)
55127	Cancelled Project Redeployed Costs	(0.347)
55127	Cancelled Project Redeployed Costs (2021)	(1.074)
55126	Cancelled Project Redeployed Costs	(0.260)
55126	Cancelled Project Redeployed Costs (2021)	(0.015)
Total other projects		(1.796)
Net amount cancelled project costs to be recovered		2.585

Source: Prepared from Exhibit 26573-X0006.01, application, Table 2.6-1, PDF pages 32-33.

6.1 Cancelled system projects

40. Having reviewed the evidence provided by ATCO Electric, the Commission finds that the cost of $0.066 million incurred in respect of the only cancelled system transmission project (the Nevis transformer project) is reasonable and the Commission approves recovery of this amount by ATCO Electric.

6.2 Cancelled "other projects"

41. As discussed earlier in Section 5, the Commission finds that ATCO Electric has complied with the requirements of Direction 5 of Decision 24375-D01-2020. The issue in that Decision

[37] As shown in Exhibit 26573-X0230, AET-CCA-2021JUL14-011(d) Attachment 1, the costs to be recovered for all cancelled customer projects (excluding those denoted in this table by (2021)) include calculations covering the years 2017-2020. This exhibit was not updated by ATCO Electric; however, the costs for all remaining cancelled customer projects denoted in this table by (2021) were provided in Exhibit 26573-X0006.01, Table 2.6-1, PDF pages 32-33. Calculations for projects 51090, 55605, 58525 and 58574 for the years 2017-2021 can be found in Exhibit 26573-X0118.01, Attachment 9.

arose from the incorrect addition of foundation materials to ATCO Electric project 55127. ATCO Electric complied with the Commission-directed true-up in the current application and the amount of $0.100 million has been included in the refund.

42. Further, with respect to projects 55126 and 55127, ATCO Electric has made the necessary adjustments in respect of the costs incurred and subsequently redeployed to other ATCO Electric projects. Given this, the Commission approves the "other" adjustments amounting to a total refund (or offset) of $1.796 million, as identified in Table 2 above.

6.3 Cancelled customer projects

43. When a customer project for the construction of transmission connection facilities is cancelled by the market participant, the customer contribution made to the TFO is retained to the extent required to keep the TFO whole for project construction costs it has incurred up to the point of cancellation. In relation to the 14 cancelled customer projects at issue in the current proceeding, ATCO Electric received and retained the customer contributions made to it by the relevant market participants to cover project costs incurred by ATCO Electric for these cancelled projects prior to their cancellation.

44. ATCO Electric is therefore not seeking recovery for capital expenditures for these projects as any capital expenditures made were offset by the relevant customer contributions made to ATCO Electric in respect of them. ATCO Electric is requesting to recover $4.381 million through its DACDA application for what it says was a benefit received by Alberta electricity customers, which represents a revenue shortfall for ATCO Electric, connected with the 14 cancelled customer projects. It indicated that this customer benefit/revenue shortfall arose because customer contributions associated with the cancelled customer projects were not removed from rate base. The customer contribution amounts therefore acted as an offset to ATCO Electric's rate base from 2017 to 2021.[38]

Background on customer contributions for customer projects

45. During a period of significant transmission build in Alberta, generally referred to as the "big build," the Commission approved a temporary credit relief mechanism called "construction work in progress in rate base" or "CWIP in rate base" accounting for short. CWIP in rate base accounting allowed TFOs additional cash flow to better support the financing of the "big build."

46. CWIP in rate base temporarily supplanted the existing and more typical mechanism of financing capital investment through an allowance for funds used during construction (AFUDC).[39] AFUDC accounting can impact a TFO's credit metrics during periods of large capital expenditures, such as the big build. Under AFUDC accounting, TFOs do not receive any incremental revenue connected with their capital expenditures until the project is energized and the expenditures are capitalized and the related capital asset is placed into service. Accordingly, until a project is in service, TFOs can have large cash outflows connected with these projects, without corresponding cash inflows resulting from the return of and on capital.

[38] Exhibit 26573-X0138.01, AET-AUC-2021JUL14-004, PDF page 71.

[39] AFUDC allows utilities to capitalize the carrying costs of financing capital investment at the weighted average cost of capital. However, these costs would be recovered through depreciation expense, or earn a return only at the time the asset was put into utility service.

47. Under CWIP in rate base accounting, the Commission approved the reflection by TFOs in their revenue requirement of return **on** the mid-year CWIP balance on direct assigned projects (return). However, the return **of** the capital investment (depreciation) was reflected in revenue requirement only when the project was energized and the related capital assets put into utility service. Under CWIP in rate base accounting, the mid-year customer contribution balance for any related customer direct assigned project offset the rate base return that would otherwise be reflected in the TFO's revenue requirement.

48. In Decision 20272-D01-2016, the Commission directed ATCO Electric to discontinue CWIP in rate base accounting:

> 88. ATCO Electric is directed, starting January 1, 2017, to **(1) resume normal regulatory AFUDC accounting for direct assigned capital, (2) discontinue CWIP in rate base for direct assigned projects**, and (3) discontinue recovering the capital portion of pension costs on a cash basis, and instead return to collection of the capital portion of pension expense as part of invested capital. ATCO Electric is directed to reflect this in the compliance filing. [emphasis added]

ATCO Electric's accounting treatment of customer contributions

49. In the current application, ATCO Electric explained that under the accounting practice it adopted in response to Direction 88, it continued to hold customer contributions related to customer projects in CWIP (in rate base) by removing from rate base only its gross project expenditures associated with the projects in question, but not the offsetting customer contributions received in respect of those same projects. Therefore, these contributions were included as offsets to ATCO Electric's rate base after January 1, 2017.

50. As summarized by ATCO Electric in an information request (IR) response:[40]

> … AET [ATCO Electric Transmission] is seeking to recover the benefit of the reduced revenue requirement that all customers [ratepayers] have received due to the inclusion of the cancelled projects' contribution WIP [work in progress] in rate base. The reduced revenue requirement related to the cancelled projects benefited all customers [ratepayers] and it would be inappropriate to seek recovery directly from the project customer.

51. ATCO Electric's rate base and the associated return on rate base included in revenue requirement (and ultimately charged to all Alberta electricity customers) was lower during the time customer contributions for those projects remained as an offset to ATCO Electric's overall rate base. As a result of this accounting treatment, ATCO Electric requested to collect what it characterized as the benefit that was afforded to all Alberta electricity customers by having the contributions related to those customer projects offset ATCO Electric's rate base.[41]

ATCO Electric's request is not properly the subject of a DACDA proceeding

52. As previously set out in the introductory sections of this decision, a deferral account allows a utility, such as ATCO Electric, to record differences between forecast and actual costs. These amounts are then reviewed by the Commission and if the Commission finds that the actual costs were prudently incurred, the utility can recover those amounts from Alberta electricity customers through rates. By establishing a deferral account, the Commission signals that the

[40] Exhibit 26573-X0167.01, AET-CCA-2021JUL14-012(b), PDF page 156.
[41] Exhibit 26573-X0006.01, application, PDF pages 33-34, paragraph 63.

amounts included in that account are subject to adjustment, such that differences between forecasts and actual costs may be refunded to or recovered from Alberta electricity customers. Therefore, by using a deferral account, Alberta electricity customers have knowledge that the amounts that they may have to pay are not final until the amount in the deferral account is disposed of on a final basis.[42]

53. The Commission has considered whether the amounts that ATCO Electric has sought in its application to recover in respect of the 14 customer cancelled projects are amounts that were booked into one or more deferral accounts and are therefore recoverable as DACDA amounts. In other words, the question is whether the $4.831 million amount represents the difference between a forecast and actual cost that may be trued up because it was subject to deferral account treatment. The Commission has determined that it is not.

54. First, there are no customer project costs for ATCO Electric to recover. ATCO Electric did not characterize the amounts as a "cost" but rather a "benefit" or "revenue shortfall." It could not do so because ATCO Electric confirmed that it has been kept whole for costs incurred for these customer projects up to the point of project cancellation.[43] ATCO Electric indicated that the customer contributions associated with the cancelled projects were retained by ATCO Electric[44] and that it would be "inappropriate" for it to recover the benefit conferred on all Alberta electricity customers from the market participant or customer for whose benefit the customer project was to be constructed.[45]

55. Second, and related to the first point, ATCO Electric does not incur carrying costs on customer projects where the customer project does not have a system component (as is the case here). Pursuant to a Commission-directed accounting procedure (Decision 2013-358), ATCO Electric must immediately account for customer contributions such that it does not earn carrying charges or return on any amount it has expended toward that customer project.

56. Specifically, in ATCO Electric's 2013-2014 GTA, the Commission examined ATCO Electric's internal contribution policy which, at that time, consisted of ATCO Electric recording customer contributions at a point when the project was nearing completion. This approach understated contributions and resulted in an overstatement of ATCO Electric's revenue requirement because, at the time, CWIP for customer projects was in rate base.

57. In Decision 2013-358, the Commission stated that both capital expenditures and the offsetting contributions are to be treated in lockstep. This alignment was particularly important at a time when "the return on CWIP for direct assigned capital projects is included in revenue requirement" through the CWIP in rate base rate relief mechanism. The Commission stated:

> 842. For regulatory purposes, a customer contribution is to be accounted for as soon as it is confirmed that a contribution will be required for the project. Waiting until capital expenditures reach ATCO Electric's approved investment level before contributions are received effectively overstates the rate base, and does not recognize the obligation for a customer contribution. This would be especially troublesome if a customer has already paid the contribution up front, ATCO Electric has incurred capital expenditures, and a number of years have passed before the contribution is recorded as a reduction to rate

[42] *Bell Canada v Bell Aliant Regional Communications,* 2009 SCC 40, [2009] 2 S.C.R. 764, paragraphs 61-63.
[43] Exhibit 26573-X0138.01, AET-AUC-2021JUL14-004, PDF page 71.
[44] Exhibit 26573-X0138.01, AET-AUC-2021JUL14-004, PDF page 71.
[45] Exhibit 26573-X0167.01, AET-CCA-2021JUL14-012(b), PDF page 156.

> base, especially during this time when the return on CWIP for direct assigned capital projects is included in revenue requirement.[46]

When contributions are treated in lockstep with the expenditures incurred, ATCO Electric does not incur carrying costs or return because the contribution offsets any expenditures made by ATCO Electric and thus negates any financing costs that would otherwise be incurred. ATCO Electric now seeks to recover forgone return because the expenditures and customer contributions were not treated in lockstep.

58. In this case, the costs of the facilities (projects that were ultimately cancelled) were covered by the customer contribution amounts. ATCO Electric was kept whole for the amounts spent in relation to each of the projects by retaining the customer contribution amounts. These are not, therefore, properly characterized as cancelled project costs.

59. In the Commission's view, what ATCO Electric has described as a "benefit" to Alberta electricity customers can equally be characterized as ATCO Electric's forgone return on rate base from 2017 to 2021. In either case, the amount is not a cost that has been booked into a deferral account. The Commission therefore finds that the $4.381 million amount is not appropriately recoverable through the DACDA application.

Recovery by ATCO Electric would constitute impermissible retrospective ratemaking

60. The Alberta Court of Appeal has described retrospective ratemaking as imposing on a utility's current electricity customers, shortfalls (or surpluses) incurred by previous generations of customers. The court noted that retrospective ratemaking is generally prohibited because it creates inequities or improper subsidizations as between past and present electricity customers (who may not be the same).[47]

61. In this case, ATCO Electric's proposal would have a retrospective effect because it is expressly seeking to recover forgone past revenue (which resulted in a benefit to its past electricity customers), from 2017 to 2021 – and to recover this revenue from ATCO Electric's current electricity customers. ATCO Electric's rates for this period were finalized,[48] as noted by the CCA,[49] under Decision 20272-D01-2016,[50] Decision 22742-D01-2019,[51] Decision 22742-D02-2019,[52] Decision 24964-D01-2021[53] and Decision 24964-D02-2021.[54]

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46 Decision 2013-358, PDF page 188, paragraph 842.
47 *Calgary (City) v Alberta (Energy and Utilities Board)*, 2010 ABCA 132, paragraph 48.
48 With some amounts subject to deferral account treatment.
49 Transcript, Volume 1 (September 29, 2021), page 104, lines 18-22.
50 Decision 20272-D01-2016, ATCO Electric Ltd., 2015-2017 Transmission General Tariff Application, Proceeding 20272, August 22, 2016.
51 Decision 22742-D01-2019, ATCO Electric Ltd., 2018-2019 Transmission General Tariff Application, Proceeding 22742, July 4, 2019.
52 Decision 22742-D02-2019, ATCO Electric Ltd., 2018-2019 Transmission General Tariff Application, Proceeding 22742, October 2, 2019.
53 Decision 24964-D01-2021, ATCO Electric Ltd., 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 1, 2021.
54 Decision 24964-D02-2021, ATCO Electric Ltd., 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021.

62. While a deferral account, such as ATCO Electric's DACDA, is a recognized exception to the rule against retroactive and retrospective ratemaking,[55] the Commission has found above that the amounts that ATCO Electric seeks to recover are not amounts that are subject to deferral account treatment. Granting ATCO Electric's request to recover any forgone return for this period would therefore constitute impermissible retrospective ratemaking and is denied.

ATCO Electric's accounting treatment of customer contributions was its own error

63. Having found that the $4.381 million is not properly recoverable through the current DACDA and that recovery of this amount would therefore constitute impermissible retrospective ratemaking, the Commission is not required to go any further. It will, however, address ATCO Electric's submissions that focus on ATCO Electric's compliance filing to Decision 20272-D01-2016 in response to Direction 88.

64. In those submissions, ATCO Electric appeared to argue that the Commission's approval of ATCO Electric's compliance with Direction 88 included approval of ATCO Electric's accounting practice of holding customer contributions related to customer projects in CWIP (in rate base) by removing from rate base only its gross project expenditures associated with the projects in question, but not the offsetting customer contributions received in respect of those same projects. This, ATCO Electric stated, resulted in a benefit that was afforded to all Alberta electricity customers, although the Commission has noted that it is also the case that it caused ATCO Electric to forgo its return on rate base on these amounts.

65. The CCA asked an IR on this point.[56] In its response, ATCO Electric did not directly address its decision, in response to Direction 88, to remove the capital expenditures from rate base, but not remove the customer contributions associated with those expenditures. Instead, ATCO Electric's IR response focused on the Commission's acceptance of certain schedules filed as part of its compliance filing to Decision 20272-D01-2016 and Direction 88. In the paragraphs that follow, the Commission examines whether its approval of ATCO Electric's compliance filing to Direction 88 caused ATCO Electric to forgo its return.

66. In Decision 22050-D01-2017[57] (which addressed compliance with Decision 20272-D01-2016 and Direction 88), the Commission accepted that ATCO Electric had complied with Direction 88. In support of its compliance with that direction, ATCO Electric referred the Commission to an attachment and schedule that described the discontinuation of CWIP in rate base for direct assigned projects in 2017 and the resumption of normal regulatory AFUDC accounting starting January 1, 2017.[58] There was nothing in ATCO Electric's compliance filing that indicated it did not remove customer contributions from rate base, nor did it bring this accounting treatment to the Commission's attention or seek guidance as to whether it would be appropriate to do so. The schedules filed by ATCO Electric did not set out how it would treat customer contributions.

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55 *Bell Canada v Bell Aliant Regional Communications,* 2009 SCC 40, [2009] 2 S.C.R. 764, paragraphs 61-63.
56 Exhibit 26573-X0167.01, AET-CCA-2021JUL14-011, PDF pages 151-152.
57 Decision 22050-D01-2017: ATCO Electric Ltd., 2015-2017 Transmission General Tariff Application Compliance Filing, Proceeding 22050, June 19, 2017.
58 Proceeding 22050, Exhibit 22050-X0019.01, PDF page 133, refers to "Attachment 4, GTA Schedule 10-1, for the discontinuation of CWIP in rate base for direct assigned projects in 2017 and GTA Schedule 9-2 for the resumption of normal regulatory AFUDC accounting starting January 1, 2017 for direct assigned capital."

67. The Commission considers that ATCO Electric's decision to implement an accounting treatment that did not remove the offsetting customer contributions from rate base was entirely within ATCO Electric's management and control. The Commission was not privy to ATCO Electric's accounting treatment. This appears to have been conceded by ATCO Electric's counsel during oral argument. There, the panel chair asked ATCO Electric's counsel to further explain the basis for ATCO Electric no longer recording CWIP in rate base while continuing its accounting practice of recording the related customer contributions as an offset to rate base.[59]

68. Through its counsel, ATCO Electric confirmed that when the Commission directed ATCO Electric to discontinue CWIP in rate base treatment and resume normal regulatory AFUDC accounting for direct assigned capital, ATCO Electric determined that Direction 88 was intended to apply to capital only, and not to the offsetting customer contributions. ATCO Electric's counsel explained that ATCO Electric's staff determined that the discontinuance of the CWIP in rate base approach for capital was a separate matter not connected to the treatment of customer contributions in CWIP, and thus should not trigger a change in the accounting treatment of construction contributions.[60] ATCO Electric also requested confirmation from the Commission that, "on a go-forward basis, the treatment of contributions be changed so that it's treated the same as CWIP."[61]

69. The Commission finds that ATCO Electric adopted a particular interpretation of Direction 88 which was not evident when it made its compliance filing to that direction. There is no indication in Decision 22050-D01-2017 that the Commission explicitly, nor impliedly approved such an interpretation, nor does the record of that proceeding set out that ATCO Electric had assumed the accounting treatment that resulted in the forgone revenue it now seeks to recover. ATCO Electric's interpretation is inconsistent with the manner that customer contributions for customer projects were expected to be accounted for, as clearly set out in Decision 2013-358. The Commission finds that ATCO Electric erred in not treating customer contributions in lockstep with capital expenditures as required by Decision 2013-358 and that the Commission was not and could not have been aware of this accounting treatment without further and specific information from ATCO Electric.

70. The Commission finds that the $4.381 million in forgone revenue that ATCO Electric seeks to recover from Alberta electricity customers results from its own error arising from its accounting treatment of customer contributions. It is not reasonable for ATCO Electric to recover this amount from Albertans.

71. For all of these reasons, the Commission denies ATCO Electric's proposed recovery of the $4.381 million amount it sought under the pretense of cancelled customer project costs. The Commission directs ATCO Electric to reduce its applied-for costs by $4.381 million in its compliance filing to this decision.

72. The Commission also requires ATCO Electric to ensure that its current and future accounting practices fully reflect the resumption of normal regulatory AFUDC accounting for its direct assigned capital. Specifically ATCO Electric must account for customer contributions in a

[59] Transcript, Volume 1 (September 29, 2021), page 72, line 2 to page 73, line 17.
[60] Transcript, Volume 1 (September 29, 2021), page 82, line 8 to page 83, line 21.
[61] Transcript, Volume 1 (September 29, 2021), page 84, lines 8-11.

manner that ensures that the customer contributions are treated in lockstep with capital expenditures as described in Decision 2013-358 on a go-forward basis.

7 Issue 3: Were ATCO Electric's capital costs on the Jasper project prudently incurred?

73. Prior to 2019, Jasper National Park, the Municipality of Jasper and the surrounding area were not connected to the Alberta Interconnected Electric System (AIES), but were served by the Astoria Hydro and Jasper Palisades power plants.[62] The isolated generating units at these power plants were either expected to reach end-of-life conditions by 2021 or the output of the units was expected to be insufficient to supply electricity customers with reliable power.

74. ATCO Electric referenced[63] a 2014 feasibility study[64] that concluded that an interconnection project was the most economical long-term solution to ensure system reliability and to provide long-term supply of power to the Jasper National Park area, the Municipality of Jasper, and industrial electricity customers within the park boundary.

75. The Jasper project,[65] which connects Jasper National Park, the Municipality of Jasper and the surrounding area to the AIES consisted of the construction of the following primary elements by ATCO Electric:

(i) the Sheridan 2085S Substation located within Jasper National Park; and

(ii) 45 kilometres of 69 kV single-circuit transmission line from the Jasper National Park boundary to the Sheridan 2085S Substation.

76. The planned in-service date in ATCO Electric's proposal to provide service (PPS)[66] was May 1, 2018, which was not met. The project was energized on May 9, 2019.

77. ATCO Electric initially requested approval of capital additions for the project in the amount of $119.1 million to December 31, 2020. In response to the Commission's July 13,

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62 Exhibit 26573-X0064.01, Jasper Transmission Interconnection.

63 Exhibit 26573-X0064.01, Jasper Transmission Interconnection, PDF page 3.

64 ATCO Electric referenced Proceeding 20272, Exhibit 20272-X0050, 54904 – Jasper Transmission Interconnection – 2015-2017 GTA, PDF pages 6-25.

65 In Decision 22125-D01-2018: Jasper Interconnection Project, Alberta Electric System Operator Needs Identification Document, Proceeding 22125, Application 22125-A001, May 4, 2018, the Commission approved a NID application from the AESO, and facility applications by ATCO Electric Transmission and AltaLink Management Ltd. to construct and operate a new substation, alter an existing substation, and construct and operate a transmission line to connect the Jasper area to the AIES.

66 The AESO may request that the TFO provide a PPS (or service proposal), along with a PPS cost estimate: 2015-002R-Service-Proposals-and-Cost-Estimating-2022-03-04.pdf (aeso.ca). The PPS provides an overview of the transmission facility project, including a project summary, an overview of the TFO's scope of work, a cost estimate, the planned schedule and any assumptions and risks. Typically, the AESO issues this request before directing the TFO to submit a transmission facility proposal (facility application) to the Commission for approval of permits and licences for a transmission facility project. For the purpose of preparing a NID, the AESO also relies on information provided by the TFO in the PPS to satisfy certain information requirements in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*.

2022,[67] letter, asking ATCO Electric to update its application to reflect the findings in Decision 27013-D01-2022 and to refile its 2021 DACDA application on the record of this proceeding, ATCO Electric adjusted its requested capital additions for this project by the following amounts:

(i) a reduction of $10.8 million associated with the sole-source Backwoods contract, as described in Decision 27013-D01-2022; and

(ii) a reduction of $2.8 million in 2021 trailing costs for the Jasper project.

78. With the two adjustments noted above, ATCO Electric requested approval of capital additions for the Jasper project in the amount of $105.5 million to December 31, 2021. These costs exceed the $84.0 million cost that ATCO Electric expected to incur in its PPS.

79. Based on its review of the record of this proceeding, the Commission has identified the following issues with respect to this project:

(i) Did ATCO Electric prudently manage and execute the consultation, permitting, regulatory and approval phases of the Jasper project?

(ii) Were ATCO Electric's electrical cable, AC mitigation and supervisory costs prudently incurred?

(iii) What is the total value of the Backwoods contract?

(iv) Does the $10.8 million reduction proposed by ATCO Electric reflect the full imprudent amount associated with the sole-source Backwoods contract?

(v) What costs were incurred by ATCO Electric for work conducted in an effort to mislead and conceal information associated with the sole-source Backwoods contract?

(vi) Should ATCO Electric be directed to track actions and costs related to its implementation of the settlement agreement concerning the Jasper project?

80. The Commission will address each of these questions in the sections that follow.

7.1 Did ATCO Electric prudently manage and execute the consultation, permitting, regulatory and approval phases of the Jasper project?

81. For the reasons set out in this section, the Commission has decided to disallow the recovery of $3.0 million for the imprudent management and execution of the consultation, permitting, regulatory and approval phases of the Jasper project.

7.1.1 ATCO Electric made unreasonable assumptions and did not adequately assess foreseeable risks which contributed to project delays

82. In this section of the decision, the Commission identifies five of ATCO Electric's assumptions for the consultation, permitting, regulatory and approval phases of the Jasper project – one that appears to have been used in the early stages of the project, and four that were used in

[67] Exhibit 26573-X0291, AUC letter - Reopening of Proceeding 26573 and ATCO Electric's application amendment.

developing its PPS estimate[68] – and explains why these assumptions were not reasonable. The Commission also explains why ATCO Electric did not reasonably assess the risks associated with consultation and third-party permit delays in its PPS estimate.

Planning assumptions used in the early stages of the project

83. In the early stages of the project, ATCO Electric made assumptions that were not realistic, given what it knew or should have known, about how long it would take to receive the approval of a detailed impact assessment (DIA) from Parks Canada. ATCO Electric required a DIA approved by Parks Canada to obtain a Development Permit to start construction within Jasper National Park. The DIA assessed current environmental conditions at ATCO Electric's facilities and right-of-way (ROW) within Jasper National Park, identified potential impacts of the project on the environment, the surrounding community, nearby pipelines, etc., and identified measures to mitigate any adverse effects caused by the project. The DIA process also required ATCO Electric to consult with any affected Indigenous communities.

84. ATCO Electric stated that it "based its expectation of PC [Parks Canada] approvals on its experience with distribution facility builds within the park. AET's impression of the line build and design, was that it was not dramatically different when compared to previously constructed distribution facilities that were built within the park boundaries. The expectation was that with respect to approvals, Parks Canada would view this approval process the same way."[69]

85. In the Commission's view, it was not reasonable for ATCO Electric to make this assumption, because: (i) it is not reasonable to expect that a transmission project would have the same characteristics and related permitting and approvals process as a distribution project; and (ii) given ATCO Electric's admittedly limited and dated experience with the Parks Canada DIA process,[70] it was reasonable to expect or within ATCO Electric's ability to confirm, that the DIA process would have evolved since ATCO Electric constructed its last distribution facility in Jasper National Park or that the requirements and rigour applied to that process could be elevated for a transmission project. In relying on the assumptions that it did, ATCO Electric misapprehended, from the very outset, the scope and complexity of the Jasper project.

PPS estimate assumptions

86. ATCO Electric had already encountered multiple consultation, permitting, regulatory and approval delays in relation to the Jasper project by the time it submitted its PPS estimate on June 1, 2016.[71] [72] Given the delays that it encountered up to that point, it knew or should have known that it could expect further challenges in the consultation, permitting, regulatory and

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[68] Exhibit 26573-X0068, Jasper Transmission Interconnection – PPS Estimate, PDF pages 10-17.

[69] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(d), PDF pages 61-62.

[70] Exhibit 26573-X0138.01, AET Information Responses to AUC Part 1 of 2, IR response AET-AUC-2021JUL14-005(b), PDF page 84.

[71] Example: using Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 60, the Commission observes that on February 2, 2015, ATCO Electric and Parks Canada set a proposed date of April to May 2016 for approval of the DIA. In April and May 2016, ATCO Electric was still working on its first DIA review submission to Parks Canada.

[72] Example: using Exhibit 26573-X0077, Jasper Transmission Interconnection – AESO Communications, PDF page 9, ATCO Electric stated in a February 2, 2016, meeting with the AESO that it would submit its PPS by April 25, 2016. On an actual basis, ATCO Electric submitted its PPS on June 1, 2016.

approval processes. It was unreasonable for ATCO Electric to make the assumptions described below in its PPS estimate about the project's expected timelines.

87. First, ATCO Electric assumed that "it would not be subjected to extreme requests, not normally required in a typical AESO direct assigned transmission project, from either Parks Canada or other stakeholders during or after the project's completion."[73]

88. In the Commission's assessment, this assumption was not reasonable. The Jasper project was significantly more complex than typical AESO direct assigned capital projects. The Jasper project had a winding, narrow ROW with limited access points, and was to be constructed within mountainous and undulating terrain in a national park, which forms part of a UNESCO World Heritage Site.[74] Applicable laws require ATCO Electric to satisfy numerous permitting requirements that are not typically contemplated on other AESO direct assigned transmission projects, including those required by Parks Canada.

89. ATCO Electric took an inconsistent position with respect to its stated assumption that it did not expect to encounter atypical requirements in relation to the Jasper project. In particular, to support the prudency of its costs, ATCO Electric explained that it needed to satisfy numerous requirements that are not typically contemplated on a transmission project[75] because of the complexities and environmental limitations of working within Jasper National Park. The requirements identified by ATCO Electric included:[76]

(i) The DIA requirements outlined above by the Commission.

(ii) The requirement to submit a Damage Prevention Plan (DPP) for approval before any activities could occur within 30 metres of the Trans Mountain Canada (Trans Mountain)[77] Pipeline which was parallel to the ROW used for the project. The DPP required mitigation measures to be implemented before construction activities could proceed parallel to the pipeline and within the existing utility corridor.

(iii) Canadian National Railway (CNR) road use and rail crossing requirements.

90. ATCO Electric knew, among other things, that it was building a transmission line in a national park, on a ROW that largely paralleled a federally regulated oil transmission pipeline and that the line would be required to cross a federally regulated railway. While ATCO Electric explained that the complexities of the additional processes and requirements enumerated above led to numerous permitting and approval delays that it said could not have been anticipated,[78] in the Commission's view most of these processes and requirements could and should have been assumed (or anticipated) to be required from the outset of project planning, and in building the PPS estimate, given the nature and complexities of the project.

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[73] Exhibit 26573-X0068, Jasper Transmission Interconnection – PPS Estimate, PDF page 10.
[74] https://whc.unesco.org/en/list/304/
[75] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, PDF page 9; and Exhibit 26573-X0262, AET Rebuttal Evidence, PDF page 68, paragraphs 132-133.
[76] Exhibit 26573-X0064.01, Jasper Transmission Interconnection.
[77] Formerly Kinder Morgan Canada.
[78] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(e), PDF pages 69-70.

91. Accordingly, ATCO Electric should have made reasonable and realistic assumptions about the possible trajectory of the processes described above, including the possibility of encountering additional requests from stakeholders (that are not typically contemplated for an AESO direct assigned transmission project) and delays in receiving the related approvals. More robust assumptions would have, in turn, required ATCO Electric to anticipate and reasonably incorporate into the earliest versions of the project plan and into the PPS estimate, foreseeable incremental stakeholder requirements and any additional process steps that could foreseeably be necessary to those requirements. This would have allowed ATCO Electric to design and implement strategies to allow for more streamlined and timely compliance with the requirements of all relevant stakeholders.

92. Second, ATCO Electric assumed that "project execution will be able to proceed as planned."[79] This statement does not accord with the following facts, all of which were known at the time that the project was being planned. ATCO Electric did not have significant experience with projects that were similar in scope, size or complexity to the Jasper project.[80] ATCO Electric admitted that it had limited and dated experience with constructing and operating distribution facilities within a national park, and it had little experience with the construction of transmission facilities in such a location. Given ATCO Electric's lack of experience and knowledge, it was not reasonable for it to assume that project execution would proceed as planned. Furthermore, given the known complexity of the Jasper project, it was foreseeable that project execution would be subject to unexpected and potentially material schedule deviations.

93. Third, ATCO Electric assumed that "the Parks Canada DIA will be completed on time and with no impact to the project's scope or schedule" and "the Parks Canada permit process will not add requirements beyond what has been accounted for, or which are beyond the project capabilities."[81] The Commission observes that Parks Canada and other stakeholders were also unfamiliar with the construction of a transmission line in a national park,[82] something that ATCO Electric could have easily ascertained at the earliest stages of the project. It is reasonable to expect that these parties would, like ATCO Electric, be subject to a learning curve, making it unreasonable for ATCO Electric to assume that the project's scope and schedule would be met without any timeline/schedule disruptions. By setting assumptions that did not anticipate these foreseeable disruptions, ATCO Electric could not put in place strategies to effectively avoid, address or mitigate them.

94. It is significant that when ATCO Electric filed its PPS, the Jasper project had already encountered multiple delays including delays related to the approval of the DIA[83] and the submission of the PPS[84] itself. Given the trajectory of the project at the time the PPS was finalized, further unexpected requirements and related delays were reasonably foreseeable. This

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79 Exhibit 26573-X0068, Jasper Transmission Interconnection – PPS Estimate, PDF page 11.

80 Exhibit 26573-X0138.01, AET Information Responses to AUC Part 1 of 2, IR response AET-AUC-2021JUL14-005(b), PDF page 84.

81 Exhibit 26573-X0068, Jasper Transmission Interconnection – PPS Estimate, PDF pages 11 and 15.

82 Exhibit 26573-X0262, AET Rebuttal Evidence, PDF page 117, paragraph 224.

83 Using Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 60, the Commission observes that on February 2, 2015, ATCO Electric and Parks Canada set a proposed date of April to May 2016 for approval of the DIA. In April and May 2016, ATCO Electric was still working on its first DIA review submission to Parks Canada.

84 Using Exhibit 26573-X0077, Jasper Transmission Interconnection – AESO Communications, PDF page 9, ATCO Electric stated in a February 2, 2016, meeting with the AESO that it would submit its PPS by April 25, 2016. On an actual basis, ATCO Electric submitted its PPS on June 1, 2016.

is further support for the finding that it was unreasonable for ATCO Electric to assume that the project would not encounter further schedule deviations.

95. ATCO Electric also assumed that the DIA approval process could proceed concurrently with the AUC's facility approval (FA) process.[85] However, it became apparent that Parks Canada wanted to wait for the FA decision before issuing its findings on the DIA.

96. Based on the record, it appears that ATCO Electric was caught off guard by this development. ATCO Electric's assumption, and the sudden nature of how this issue developed, appear to demonstrate: (i) a failure to identify and communicate this foreseeable issue earlier in the project's lifecycle; and (ii) that ATCO Electric's stakeholder consultation was not as comprehensive as it claimed.[86] [87]

97. Fourth, ATCO Electric assumed that "an AUC hearing will not be required."[88] While the wording of this assumption was not clear as to whether ATCO Electric meant that no oral hearing, no written hearing or no hearing (at all) would be required, the Commission has interpreted it to be referring to an oral hearing. This is because it would be highly unlikely for a project such as the Jasper project to proceed without any AUC hearing at all. Even with this more generous interpretation, the Commission considers this assumption to be unreasonable. It was foreseeable given the size, complexity and location of the project, that interested parties would apply to intervene in the Commission's FA process. Given ATCO Electric's significant experience with the AUC's FA process, it also knew or should have known that any such interventions would, by law,[89] require the Commission to hold a written hearing at a minimum, and that in practice, an oral hearing was more likely to be required than not.

Risk assessment for consultation and third-party permit delays

98. In its PPS, ATCO Electric identified the risk of consultation and third-party permit delays. It assessed this risk at a 40 per cent probability.[90] In response to a Commission IR, ATCO Electric explained, in relation to this risk: (i) that it did not anticipate the large delays from either Parks Canada or Trans Mountain, nor the additional requirements from Parks Canada and Trans Mountain and the compounding impacts of these delays; (ii) that these impacts (large delays, additional requirements, compounding impacts) were not foreseeable at the time of the PPS estimate and risk register development, and therefore were not adequately quantified in the risk register filed with the PPS; and (iii) that it had applied a low probability to this risk.

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85 Exhibit 26573-X0262, AET rebuttal evidence, PDF pages 66-67, paragraphs 128-130, and Exhibit 26573-X0138.01, AET Information Responses to AUC Part 1 of 2, IR response AET-AUC-2021JUL14-005(a), PDF pages 82-84.

86 Exhibit 26573-X0138.01, AET Information Responses to AUC Part 1 of 2, IR response AET-AUC-2021JUL14-005(b), PDF page 84.

87 The record of communications between ATCO Electric and the AESO (See for example Exhibit 26573-X0077, Jasper Transmission Interconnection – AESO Communications and Exhibit 26573-X0071, Jasper Transmission Interconnection – Monthly AESO Progress Reports) also demonstrate minimal communication of issues and risks (and in particular schedule risks) with a critical stakeholder on the Jasper project.

88 Exhibit 26573-X0068, Jasper Transmission Interconnection – PPS Estimate, PDF page 11.

89 *Alberta Utilities Commission Act*, Section 9(2).

90 Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(e), PDF pages 69-70.

99. The Commission finds that ATCO Electric did not reasonably assess the risk of consultation and third-party permit delays.

100. As identified above, neither the stakeholders nor ATCO Electric were experienced with constructing a transmission line through a national park and the related processes. Given this lack of experience and knowledge, and the complexities of the project, it was or should have been evident, based on what ATCO Electric knew or should have known, that it would more than likely encounter schedule deviations and additional unexpected requirements from stakeholders; that these schedule deviations and requirements could have a negative effect on project timelines and create further delays; and that these issues could have compounding effects (e.g., delays) on both schedule and costs. Furthermore, given the trajectory of the project at the time the PPS was finalized (as previously described, it had encountered multiple delays even prior to the finalization of the PPS), the prudent course would have been for ATCO Electric to comprehensively consider the possibility of further delays and to plan (including steps to avoid and mitigate) accordingly. It did not do so.

101. The Commission finds that given what ATCO Electric knew or should have known at the time about the project, the risk of consultation and third-party permit delays should have been assessed at a higher probability. Further, it was imprudent for ATCO Electric to not conduct a more thorough assessment of: (i) the potential for additional unexpected requirements and schedule deviations; (ii) the associated impacts of these events including additional and compounding delays and cost increases; and (iii) strategies to avoid, address and mitigate these potential delays and cost increases.

102. ATCO Electric stated that it would have increased its forecasts to accommodate "large" delays from either Parks Canada or Trans Mountain, and the additional requirements from Parks Canada or Trans Mountain that further impacted the resulting impact of the "large" delays on project costs, had it been aware of these issues when preparing its PPS estimate.[91] It therefore contended that in the end, the actual costs would have been the same as its current applied-for costs for the Jasper project.

103. The Commission is of the view that increases to the PPS estimates are not the only way that ATCO Electric could have addressed the potential for delays. As set out above, prudent planning requires anticipating deviations from the plan. A sufficiently realistic assessment of the foreseeable risks associated with the Jasper project could have resulted in the identification of a number of strategies to address them, including more proactive communications, greater front loading of tasks related to permitting requirements, and more robust plan B (or C) contingency planning to **avoid** additional costs rather than automatically equating the realization of foreseeable risks with incremental project costs.

104. Based on the "full version" of ATCO Electric's PPS risk register (filed in its rebuttal evidence), it appears that ATCO Electric planned to use some of these strategies to avoid the risk of "construction timing restriction due to environmental and species at risk," setting out the following mitigation strategies: (i) "have a strong project plan from all disciplines with plan B backup;" and (ii) "front end planning at all stage before execution starts to ensure sensitive areas are identify [*sic*] early and are shared with the project team."[92] Similar mitigation measures could

[91] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(e), PDF pages 69-70.
[92] Exhibit 26573-X0263, Section 3.1 Attachment 1, PDF page 3.

and should have been adopted to avoid and mitigate all schedule-related risks on the Jasper project (including risks associated with requirements from Parks Canada during the DIA process). Based on the Commission's review of the record of this proceeding, such mitigation measures were not identified or used for any of the other risks included in ATCO Electric's risk register or discussed in this section. It is also not clear, whether ATCO Electric conducted any other contingency planning or developed any other mitigation strategies[93] related to timing delays.[94]

105. With an earlier and more thorough assessment and weighing of consultation and third-party permit delay risks, ATCO Electric could have developed a more effective and cost-efficient strategy to mitigate the full impact of the additional, compounding and prolonged delays (and associated cost increases) that it encountered during the consultation, permitting, regulatory and approval phases of the project (including the delay in the start of construction that had a material effect on costs, as discussed in further detail below).

106. In conclusion, ATCO Electric has not persuaded the Commission that many of the assumptions built into its project plan were reasonable, or that it proactively identified, assessed and developed plans to avoid and mitigate critical risks to the Jasper project schedule. As a result, the Commission is also not persuaded that ATCO Electric had effective and cost-efficient strategies to avoid or mitigate the delays (and associated cost increases) that it encountered during the consultation, permitting, regulatory and approval phases of the project. Based on the information available to ATCO Electric from the early stages of the project, and leading up to its PPS estimate, the Commission finds that additional requirements and requests, non-standard timelines and schedule deviations were foreseeable. Failure to identify and plan for these foreseeable risks resulted in the major delays ultimately encountered by ATCO Electric during the consultation, permitting, regulatory and approval phases of the project, the late start to construction activities and the associated increased project costs. While the Commission acknowledges that the standard for project management and the related development of assumptions is not perfection and that not all risks are foreseeable, the record of ATCO Electric's underlying assumptions in relation to the Jasper project shows that ATCO Electric adopted a pattern of adherence to unrealistic assumptions and, as a result, unrealistic project timelines.

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[93] In Exhibit 26573-X0262, AET rebuttal evidence, PDF pages 65, 68 and 78, paragraphs 125, 135 and 150, ATCO Electric stated that it worked with stakeholders throughout the duration of the project to expedite approvals in order to mitigate and avoid delays. Apart from the examples that ATCO Electric provided, where it attempted to expedite approval of the final DIA after it was filed, the Commission was unable to find additional evidence demonstrating and confirming that ATCO Electric attempted to use this as a mitigation strategy during all phases of the project to avoid foreseeable risks (i.e., unexpected requirements and consultation delays). Furthermore, Parks Canada stated that the DIA could not be reviewed by ATCO Electric's requested deadline, because the DIA was received later than expected and there were still outstanding submissions from ATCO Electric.

[94] The Commission asked ATCO Electric in AET-AUC-2021JUL14-012(d) to discuss whether it used any mitigation strategies to avoid cost escalations from delays (e.g., once it was identified that Parks Canada had a complex permitting process, did ATCO Electric consider the risks associated with any potential delays in this permitting process, and did ATCO Electric employ any strategies to mitigate these risks). In Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(d), ATCO Electric responded that it worked with stakeholders to expedite approvals and it provided justification for its decision to continue construction in the fall of 2018 under a compressed schedule. Otherwise, ATCO Electric did not identify any mitigation strategies in response to this IR.

7.1.2 ATCO Electric's management and execution of the consultation, permitting, regulatory and approval processes led to delays in the start of construction

107. This section examines three regulatory approval processes completed in relation to the Jasper project that ATCO Electric has not persuaded the Commission were prudently managed and executed. The first two approvals, the DIA and special activity permits (SAPs) approvals, were required by Parks Canada. The third approval is the damage prevention plan (DPP) for ATCO Electric to be able work near and cross the Trans Mountain Pipeline. Each of these approvals was required before ATCO Electric could commence construction of the Jasper project.

108. Importantly, the Commission finds that the proceeding record contains significant and material information gaps in relation to these approval processes. This is unreasonable, given the material cost increases that occurred as a result of the delays that ATCO Electric encountered in the DPP and DIA processes (primarily the costs associated with the delay in the start of construction, which are discussed in greater detail below). Because of these information gaps, the Commission is unable to conclude that ATCO Electric managed all aspects of the DIA, SAP and DPP processes in a prudent and cost-efficient manner. Accordingly, the Commission finds that ATCO Electric did not meet its onus to demonstrate that the associated cost of those delays were all prudently incurred.

The DIA and SAP regulatory permitting process

109. Parks Canada approved ATCO Electric's DIA on June 22, 2018.

110. Parks Canada's approval took over two years longer to obtain than ATCO Electric had initially projected. On February 2, 2015, ATCO Electric and Parks Canada proposed a date of December 18, 2015, for ATCO Electric to submit the final DIA with final approval of the DIA expected in April to May of 2016.[95] In May of 2016, ATCO Electric was still working on its first DIA review submission to Parks Canada.

111. All projects require an effective approach to communicating with stakeholders. The circumstances and added complexity of the Jasper project would, however, foreseeably and reasonably require an enhanced level of communication and a special emphasis on stakeholder communication within the larger project management framework. This is because it was critical for ATCO Electric to identify stakeholder requirements in a comprehensive and prompt manner, and to proactively manage risks (approval delays, the need for revisions, etc.) to the project to avoid and to mitigate delays, and the potential cost impacts of a late start to construction. ATCO Electric knew, or should have known,[96] that delays would have a cascading effect, due to the seasonal restrictions on construction and as such, the need to avoid or mitigate delays. It was

[95] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 60.

[96] The Commission observes that the evidence is inconsistent on this point. In Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(e), PDF pages 69-70, ATCO Electric stated that it did not anticipate or foresee the large delays from either Parks Canada or Trans Mountain Canada, nor the additional requirements from Parks Canada and Trans Mountain Canada that further impacted the resulting impact of these delays on project costs. However, ATCO Electric filed the "full version" of its PPS risk register as Exhibit 26573-X0263, Section 3.1 Attachment 1 at the time of rebuttal evidence, where it appears that ATCO Electric at least considered the possibility of the cascading effects/impacts from delays in the consultation, permitting, regulatory and approval phases of the project.

foreseeable that the related requirement for early, frequent and effective communication with stakeholders would be a significant risk mitigation tool.

112. There is evidence on the record of this proceeding that demonstrates that ATCO Electric did not communicate effectively with Parks Canada to understand its DIA requirements:

(i) July 28, 2016, meeting minutes: Parks Canada stated that ATCO Electric's "archeological and historical data information did not satisfy its wants and needs," and Parks Canada's Archeological and Historical Department stated that they had raised concerns before about the lack of communication between Parks Canada and ATCO Electric on the proposed route of the powerline.[97]

(ii) August 11, 2016, meeting minutes: Parks Canada identified concerns with the project files that ATCO Electric issued to Parks Canada for review, stating that temporary workspaces were not shown, and that an overview assessment of the route was not issued.[98]

(iii) July 20, 2017, letter to ATCO Electric: Parks Canada stated that it reviewed ATCO Electric's revised development permit documents and drawings, and determined that "there are project footprint alterations … that have not been factored into the Archeological Impact Assessment, and that work remains to be completed."[99]

(iv) September 29, 2017, letter to ATCO Electric: Parks Canada stated that it was continuing its review of the DIA, development permits and record of consultation, and that some of the associated documents were still outstanding from ATCO Electric.[100]

113. Accordingly, based on the record of this proceeding, the Commission finds that ATCO Electric's communication efforts were ineffective at identifying and understanding Park Canada's requirements in a timely and comprehensive manner. ATCO Electric failed to effectively identify or anticipate changes to the DIA process, or to Parks Canada's expectations since ATCO Electric's previous encounter with Parks Canada on a distribution build. It also appears that ATCO Electric failed to effectively understand the necessary requirements to obtain approval of its DIA in a timely manner.

114. The delays connected with Parks Canada's approval of the DIA are important. There were interdependencies between Parks Canada's approval of the DIA and ATCO Electric's ability to apply for and obtain SAPs from Parks Canada. To apply for and obtain the SAPs, Parks Canada had to approve ATCO Electric's DIA. Accordingly, ATCO Electric's delay in obtaining approval of its DIA directly led to a delay in its ability to apply for and obtain its SAPs, and, in turn, to delays in the commencement of construction (including preparation activities such as brushing/clearing).

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97 Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 233.
98 Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 239.
99 Exhibit 26573-X0268, Section 3.2.2 Attachment 1, PDF page 7.
100 Exhibit 26573-X0268, Section 3.2.2 Attachment 1, PDF page 16.

115. ATCO Electric indicated that it encountered critical delays in obtaining SAPs from Parks Canada.[101] SAPs were required for brushing/clearing, access and site preparation activities, among other things. ATCO Electric applied for SAPs in June and July 2018, after receiving approval of the DIA from Parks Canada. At that time, ATCO Electric expected the SAPs to have a two-week approval timeline. However, these SAPs were not approved by Parks Canada until August to October 2018, up to three months after they were expected.

116. ATCO Electric began to experience delays in the SAP approval process on, and after, July 2018. This was a critical period in the project's lifecycle, yet ATCO Electric did not explain why the SAP approval was delayed beyond the two-week period or describe the cause(s) of the delay. It appears to the Commission that ATCO Electric may not have provided the full record of communication with Parks Canada,[102] particularly with respect to the SAP approval process. ATCO Electric did not provide any meeting minutes with Parks Canada after July 19, 2018.[103] Either there were no further meetings with Parks Canada after this time, there were meetings for which there are no minutes or notes, or ATCO Electric has notes of meetings that it has not filed on the record of this proceeding. In any case, the Commission is concerned. Either ATCO Electric has not produced relevant and probative information or the absence of meeting records demonstrates that ATCO Electric's communications with Parks Canada were significantly lacking during this time period. In addition, the correspondence that ATCO Electric filed during rebuttal evidence was sporadic and did not provide any clear insight into the cause of delays during the SAP approval process.[104]

The DPP regulatory permitting process

117. Based on its review of the Parks Canada communications filed by ATCO Electric,[105] it appears to the Commission that ATCO Electric encountered significant delays in reaching an agreement to access Trans Mountain's utility corridor. In the minutes of an October 8, 2015, meeting between ATCO Electric and Parks Canada, ATCO Electric first informed Parks Canada that talks had started with Trans Mountain, and that Parks Canada had requested a joint meeting between all stakeholders once the framework of an agreement was in place.[106]

118. In the December 17, 2015, meeting minutes, a due date of "Late Q1 2016 or early Q2 2016" was established for this meeting.[107] This deadline was pushed back multiple times, and in the February 23, 2017, meeting minutes, ATCO Electric provided a final updated due date of "Late Q3, 2017"[108] (a delay of more than one year). In the December 15, 2016, meeting minutes, ATCO Electric informed Parks Canada that the deadline to complete the joint agreement to

[101] Exhibit 26573-X0138.01, AET Information Responses to AUC Part 1 of 2, AET-AUC-2021JUL14-005(b), PDF page 86.
[102] ATCO Electric did not provide any meeting minutes with Parks Canada: (i) between May 4, 2017, and August 10, 2017; (ii) between August 10, 2017, and July 19, 2018; and (iii) after July 19, 2018.
[103] Exhibit 26573-X0268, Section 3.2.2 Attachment 1, PDF page 28.
[104] Exhibit 26573-X0268, Section 3.2.2 Attachment 1.
[105] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1.
[106] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 97.
[107] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 125.
[108] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 319.

access Kinder Morgan Canada's utility corridor was set at April 30, 2017.[109] The January 12, 2017, meeting minutes also reflect that the DPP was under review for the seventh time.[110]

119. ATCO Electric did not explain the nature or cause(s) of the Trans Mountain-related delays outlined above (e.g., why the DPP was reviewed seven times). There is also insufficient evidence to demonstrate that ATCO Electric tried to employ any mitigation strategies to avoid the delays or related cost escalations, once it was evident that delays were occurring and ongoing in the approval process with Trans Mountain.

ATCO Electric did not provide requested information

120. The onus rests on ATCO Electric to provide the evidentiary support for the requests in its application. There are instances where ATCO Electric was asked to provide supporting information, but declined to do so or provided incomplete responses.

121. In AET-AUC-2021JUL14-012(d),[111] the Commission asked ATCO Electric to provide a narrative that outlines and explains **all** of the major delays that ATCO Electric encountered on the Jasper project, including Parks Canada's permitting process, and the negotiation process with Trans Mountain, in chronological order. The Commission also asked ATCO Electric to explain the causes of these delays.

122. In response, ATCO Electric provided a high-level and general summary of the delays that occurred during the period following the submission of its FA and DIA, and immediately prior to the start of project construction. ATCO Electric did not provide the requested narrative that chronicles all of the major delays that occurred in the DIA process from start to finish with an explanation describing each delay, nor did it provide the requested information in respect of any of the other numerous regulatory and permitting processes that were delayed during this time period. The failure to provide the requested information includes information on the DPP-related delays discussed above, and the delays during the DIA process.[112] Furthermore, ATCO Electric did not explain the cause of the delays (e.g., why the DIA involved up to nine rounds of reviews, what necessitated each additional review, etc.) or provide information about what party or parties contributed to or were responsible for the delays.

123. In AET-CCA-2021JUL14-003(a)[113] the CCA asked ATCO Electric to "provide all emails, letters, meeting notes, meeting minutes and all other correspondence between AET and the AESO, Parks Canada, the NEB/CER, and TMC (formerly Kinder Morgan) that relate to the

[109] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 288.
[110] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 295.
[111] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(d).
[112] Using Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003(a) Attachment 1, PDF page 60, the Commission observes that on February 2, 2015, ATCO Electric and Parks Canada proposed a date of December 18, 2015, to submit the final DIA. This schedule also assumed that only one review would be necessary. On an actual basis, ATCO Electric submitted its final DIA on June 14, 2017. That DIA went through what appears to be five rounds of reviews (the Commission does however observe that in Exhibit 26573 X0262, AET rebuttal evidence, PDF page 66, ATCO Electric lists the DIA as having gone through nine rounds of reviews).
[113] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003.

Jasper Transmission Interconnection." ATCO Electric declined to provide the communications with Trans Mountain.

7.1.3 The delays in the start of construction caused ATCO Electric to incur increased costs

124. The DIA set a narrow construction window for the Jasper project.[114] Under the DIA, ATCO Electric could only undertake construction activities outside of peak tourist season in Jasper National Park. Parks Canada defined peak tourist season as June 1 to September 5.

125. ATCO Electric's failure to obtain approval of the DIA, DPP and SAPs in a timely manner and well outside of its anticipated schedule at the time of the PPS, resulted in compounding issues that created significant delays to ATCO Electric's project schedule. This had a material effect on project timing, and resulted in increased costs associated with the consultation, permitting, regulatory and approval phases of the project (including project management costs).

126. ATCO Electric predicted that construction activities on the project would begin in September 2018.[115] However, because of the delays identified above that ATCO Electric encountered during the consultation, permitting, regulatory and approval phases of the project (including the approval of SAPs from Parks Canada and approval of its DPP from Trans Mountain), construction did not start until October 23, 2018.[116]

127. For this reason, ATCO Electric chose to compress its construction schedule (i.e., accelerate construction) by opening up additional/multiple simultaneous work fronts along the ROW, in order to complete the project within Parks Canada's construction window. Consequently, ATCO Electric incurred increased costs to support construction activities on multiple work fronts (including access matting, line construction, supervision, etc.) rather than doing the work sequentially as originally planned. A breakdown of the additional costs attributable to the project start delays was filed by ATCO Electric in response to Commission IR AET-AUC-2021JUL14-012(e).[117]

128. As discussed above, the Commission's IR AET-AUC-2021JUL14-012(d)[118] also asked ATCO Electric to provide a narrative of all the major delays encountered in the project, including an explanation of how these delays contributed to cost escalations by project line item with the associated variances. It is not clear to the Commission whether the breakdown filed by ATCO Electric in AET-AUC-2021JUL14-012(e) was a comprehensive listing of all delays encountered. It appears that this breakdown provides variances related to specific construction activities that are tied to the project start delays, but the Commission is unsure whether it includes owner's costs associated with delays in the DIA process or other similar delays.[119]

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[114] Exhibit 26573-X0262, AET rebuttal evidence.
[115] Exhibit 26573-X0262, AET Rebuttal Evidence, PDF pages 55-56, paragraphs 106-107.
[116] In Exhibit 26573-X0064.01, Jasper Transmission Interconnection, PDF page 12, ATCO Electric stated that brushing and site access work in advance of line construction activities could not commence until October 2018, while line construction activities were delayed until late November 2018.
[117] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(e), PDF pages 68-69.
[118] Exhibit 26573-X0139.01, AET Information Responses to AUC Part 2 of 2, IR response AET-AUC-2021JUL14-012(d), PDF pages 64-66.
[119] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, PDF page 25.

129. While, for all of the reasons set out in this section, the Commission is not persuaded that ATCO Electric managed and executed the consultation, permitting, regulatory and approval phases of the Jasper project in a prudent manner, the Commission is also not persuaded that all of the costs connected with the project delays are attributable to ATCO Electric's imprudence. Such a finding would imply that all of the delays in the consultation, permitting, regulatory and approval phases of the project were avoidable with prudent project management and execution. The Commission does not believe that this is a reasonable conclusion.

130. Given the complexities of the Jasper project, the Commission acknowledges that it was unlikely that all of the delays that ATCO Electric encountered, and the increased costs attributable to such delays, were entirely caused by ATCO Electric's own imprudence and therefore that all delays and associated costs could have been avoided. For example, ATCO Electric encountered delays during the FA proceeding, not all of which were entirely avoidable given the circumstances and complexities of the project.

131. In its submission, the CCA recommended a disallowance of $5.9 million to the Jasper project's costs for imprudent project management (including schedule management). In the Commission's view, a disallowance of this magnitude would overstate the costs associated with ATCO Electric's imprudent management and execution of the Jasper project. Based on the Commission's detailed analysis set out above, the Commission finds that a lower disallowance is appropriate in the circumstances.

132. Accordingly, the Commission directs ATCO Electric to reduce its applied-for costs for the Jasper project by $3.0 million in its compliance filing to this decision, which represents approximately three per cent of the current total applied-for project costs and approximately 14 per cent of the variance between PPS forecast and actual applied-for project costs. The Commission notes that this disallowance includes amounts for the disallowance attributed to its findings in Section 7.2.3 of this decision provided below.

7.2 Were ATCO Electric's electrical cable, AC mitigation and supervisory costs prudently incurred?

7.2.1 Were ATCO Electric's electrical cable costs prudently incurred?

133. The Jasper project was the first time that ATCO Electric used the 69 kV rated Aerial Cable System (ACS) overhead conductor in a transmission application. Actual costs incurred to incorporate the overhead conductor into the Jasper project design were higher than the estimate, with the overhead conductor cited by ATCO Electric as having contributed $3 million to the increased project costs. The CCA raised concerns regarding ATCO Electric's limited experience with the overhead conductor and the potential for this limited experience to have led to poor planning and higher costs.

134. The majority of the variance related to the 69 kV rated ACS overhead conductor was attributed to the cost of physical equipment[120] and the Commission is satisfied that these costs were prudently incurred. Furthermore, based on its review of the record of this proceeding, the Commission is not persuaded that the costs associated with incorporating this overhead conductor into the project design were imprudently incurred. Consequently, the Commission

[120] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, PDF page 18.

approves the costs associated with the ATCO Electric's use of the 69 kV rated Hendrix ACS overhead conductor as filed.

7.2.2 Were ATCO Electric's AC mitigation costs prudently incurred?

135. ATCO Electric interacted with ATCO Pipelines & Liquids (ATCO Pipeline) and Trans Mountain, who own CER-regulated pipelines in the utility corridor to assess, and where appropriate, mitigate the effect ATCO Electric's transmission line imposes, through electrical interference, on these pipelines.

136. ATCO Pipeline and Trans Mountain independently hired consultants to conduct the AC mitigation studies for their respective pipelines. ATCO Electric identified unexpected results in the Trans Mountain study and hired its own consultant to provide recommendations on required AC mitigation actions for the Trans Mountain-owned asset.[121] Trans Mountain's consultant and ATCO Electric's consultant were unable to agree upon a recommended course of AC mitigation, which resulted in ATCO Electric and Trans Mountain jointly engaging an independent consultant to review the initial studies, conduct its own analysis, and provide final recommendations. The Commission understands that this process is in accordance with standard industry practice and therefore finds that it was a reasonable course of action, given the circumstances of this project.

137. The Commission finds that the costs of the AC mitigation studies and of the AC mitigation measures that arose from those studies were prudently incurred and approves ATCO Electric's AC mitigation costs as filed.

7.2.3 Were ATCO Electric's Trans Mountain supervisory and advisory costs prudently incurred?

138. The DPP for the Trans Mountain pipeline outlines protection measures including requiring construction work near the pipeline to be supervised. The area within 30 metres to each side from the centreline of CER-regulated pipelines is an area where extra precautions and authorizations (written consent of the pipeline company or an Order issued by the CER) are required for certain activities to occur.[122] Accordingly, ATCO Electric incurred costs to have Trans Mountain inspectors on site to provide supervision pursuant to the DPP.

139. ATCO Electric understood that the requirement outlined in the DPP for onsite Trans Mountain inspectors would cease once the necessary access mats were installed. However, Trans Mountain ultimately required inspectors to be on site any time construction activities occurred within 7.5 metres of Trans Mountain's pipeline. ATCO Electric conveyed that this supervision requirement was unexpected and was therefore not considered during the development of the cost estimate in the PPS. When more information became available on the requirement, ATCO Electric updated its cost estimate.

140. The Trans Mountain supervisory and advisory costs, which included the cost of Trans Mountain inspectors, totalled $4.6 million over the course of the Jasper project.

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[121] Exhibit 26573-X0139.01, AET Information Response to AUC Part 2 of 2, PDF page 21.

[122] *Canadian Energy Regulator Pipeline Damage Prevention Regulations – Authorizations*, SOR/2016-124, s. 2 and 6 to 14

141. Based on the record of this proceeding, the Commission is not persuaded that ATCO Electric's consultation efforts with Trans Mountain were comprehensive. ATCO Electric did not provide a comprehensive record of communications with Trans Mountain on the record of this proceeding.[123] Moreover, the timing and unexpected nature of the on site supervision requirement suggest that ATCO Electric's communications were not fully effective. It is unclear to the Commission why this requirement could not have been identified much sooner, given what was known about the proximity of the transmission line to the Trans Mountain's pipeline.

142. Had ATCO Electric identified these requirements at an earlier stage in the project's lifecycle (through effective and comprehensive stakeholder consultation), it could have explored the potential for mitigation of supervisory costs either with Trans Mountain or in terms of its own construction plan. However, ATCO Electric's reactive approach precluded any opportunity to minimize the need for Trans Mountain supervisors on site, the duration that they would be required to be on site, or the costs associated with this requirement.

143. The Commission is therefore unable to conclude that all of ATCO Electric's applied-for costs, for Trans Mountain's supervisory and advisory costs, were prudently incurred. The disallowance of imprudently incurred costs associated with these findings is reflected in the $3.0 million disallowance directed by the Commission in Section 7.1.

7.3 What is the total value of the Backwoods contract?

144. In the amendment to its application filed August 11, 2022,[124] ATCO Electric proposed to reduce the amounts it applied to recover for the Jasper project by $10.8 million.[125] ATCO Electric indicated that the $10.8 million reduction was intended to be a proxy for the access services rates that ATCO Electric would have obtained from a vendor under a competitive bidding process, but did not obtain because it decided to approve a direct contract award to Backwoods.

145. ATCO Electric determined the $10.8 million reduction (associated with the sole-source Backwoods contract) by using the differences between:[126] (i) the actual rates paid to Backwoods on the Jasper project; and (ii) the rates from ATCO Electric's 2018 Master Service Agreement (2018 MSA) with TerraPro for a separate scope of access services work undertaken on a different project. At a high level, ATCO Electric then applied the differences to the total value of the Backwoods contract, which ATCO Electric identified as $33.1 million.[127] Accordingly, before the Commission can consider whether the $10.8 million reduction proposed by ATCO

[123] Exhibit 26573-X0164, AET Responses to CCA Part 1 of 2, AET-CCA-2021JUL14-003.
[124] Exhibit 26573-X0295, Cover Letter enclosing AET Amended 2018-2021 Deferral Application.
[125] In Proceeding 27013, Exhibit 27013-X0069, Settlement Agreement and Agreed Statement of Facts, PDF pages 6-7, paragraph 12, AUC enforcement staff and ATCO Electric agreed that ATCO Electric would amend its 2018-2020 DACDA application (Proceeding 26573) to exclude from its claim all costs above fair market value for access services for the Jasper project, which was estimated by ATCO Electric to be $10.8 million. The Commission approved this amount in principle in Decision 27013-D01-2022, PDF page 25, paragraph 105, as part of its approval of the settlement agreement. Subsequently, in Exhibit 26573-X0295, Cover Letter enclosing AET Amended 2018-2021 Deferral Application, PDF page 1, ATCO Electric excluded from its requested recovery all costs above fair market value for access services for the Jasper project by $10.8 million, as proposed in the Settlement Agreement and Agreed Statement of Facts and Contraventions and approved in principle by the Commission in Decision 27013-D01-2022.
[126] Transcript, Volume 1 (January 25, 2023), page 25, lines 20-23, page 26, lines 17-25 and page 27, lines 1-9.
[127] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, Table 7: Site Preparation and Survey Costs, PDF pages 19-20.

Electric reflects the full imprudent amount associated with the sole-source Backwoods contract, it must confirm the total value of the Backwoods contract.

146. There are at least three sources of information on the record of this proceeding that indicate different amounts paid by ATCO Electric under the Backwoods contract.

147. The first source of information is a breakdown filed by ATCO Electric that shows the initial value of the Backwoods contract, and subsequent change orders:

Table 3. Initial value of Backwoods access services contract and subsequent change orders

	Date issued	Matting	Clearing	Hydrovac	Total
		($ million)			
Initial contract	2018	13.0	1.5	0.5	15.0
Change order 1 and 2	November 2018	5.8	0.9	-	6.6
Change order 3 and 4	January 2019	3.0	1.3	-	4.3
Change order 5	March 2019	6.3	3.2	-	9.4
Total		28.1	6.9	0.5	35.3

Source: Refer to ATCO Electric's May 2021 REF in Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF page 76.

148. The second source of information about amounts incurred under the Backwoods contract comes from an investigation report prepared by the security team of ATCO Electric's indirect corporate parent. ATCO Corporate Security reported that a sixth change order valued at $1.4 million was approved for the Backwoods contract on May 14, 2019.[128]

149. In referencing the change orders, the Commission understands that the issuance of a change order means that cost increases were authorized, but that not necessarily all amounts authorized under a change order were incurred. With that said, it is unclear why a sixth change order would have been issued, if work could have been completed under the Backwoods contract pursuant to a prior change order.

150. The Executive Summary of ATCO Corporate Security's investigative report indicated that the final award to Backwoods Contracting was in the amount of $35,305,889. It also noted that ATCO Electric claimed, in its 2018-2020 DACDA application, $37 million for the Backwoods Energy direct award contract.[129]

151. The third source of information about the value of the Backwoods contract came from the Agreed Statement of Facts made between ATCO Electric and AUC Enforcement staff. That instrument indicates that the total amount ultimately paid to Backwoods was $31.1 million for matting-related work and $2.1 million for brushing/clearing-related work.[130]

152. The Commission observes the following inconsistencies in the information that ATCO Electric provided.

[128] Exhibit 26573-X0349, Documents provided to Enforcement Staff by ATCO Electric during the Investigation, PDF page 30.
[129] Exhibit 26573-X0349, Documents provided to Enforcement Staff by ATCO Electric during the Investigation, PDF page 30.
[130] Exhibit 26573-X0346, Agreed Statement of Facts, PDF page 23, paragraph 58.

153. First, in its application, ATCO Electric stated that it incurred $2.1 million in brushing/clearing costs on the Jasper project.[131] However, based on the change order information, it appears that ATCO Electric approved $6.9 million in brushing/clearing costs as part of the Backwoods contract, in addition to any amounts for brushing/clearing that may have been paid under change order 6.

154. Second, ATCO Electric applied a reduction (for imprudently paying rates to Backwoods that were above fair market value) to a total contact value of $33.1 million (before ATCO Electric's reduction).[132] However, it is unclear whether the total value of the Backwoods contract was $33.1 million because:

(i) the total value of the initial contract and all subsequent change orders is $36.7 million;[133] and

(ii) the ATCO Investigation Executive Summary stated that the final award to Backwoods Contracting was $35,305,889 (a very precise number) or $37 million (as the costs included in ATCO Electric's 2018-2020 DACDA application).

155. Third, it appears that ATCO Electric incurred $0.5 million in hydrovac costs. However, based on the record of this proceeding, the Commission is unable to confirm which category of costs (as outlined in the Jasper project summary) includes hydrovac costs, and whether ATCO Electric made an adjustment to its hydrovac costs for the imprudent amounts associated with the sole-source Backwoods contract.

156. Given this lack of clarity, the Commission directs ATCO Electric, in its compliance filing to this decision:

(i) to explain the inconsistencies identified above in the total value of the amounts incurred under the Backwoods contract;

(ii) to confirm the total amount that ATCO Electric is requesting approval to recover for the Backwoods direct award contract in its 2018-2021 DACDA application;

(iii) to provide a breakdown of the amount in subpart (ii) by cost category (mat rentals, mat purchases, mat movement, mat cleaning, brushing/clearing, hydrovac, etc.);

(iv) to confirm that ATCO Electric applied the appropriate and necessary adjustments (i.e., consistent with the methodology that it used to calculate its currently proposed $10.8 million reduction)[134] to each cost category from part (iii), by reducing the imprudent amounts associated with the sole-source Backwoods contract; and

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[131] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, Table 7: Site Preparation and Survey Costs, PDF pages 19-20.

[132] Exhibit 26573-X0064.01, Jasper Transmission Interconnection, Table 7: Site Preparation and Survey Costs, PDF pages 19-20.

[133] $15.0 million initial contract + $6.6 million for change order 1/2 + $4.3 million for change order 3/4 + $9.4 million for change order 5 + $1.4 million for change order 6 = $36.7 million.

[134] The details were filed on the confidential record: Exhibit 26573-X0310-C, Attachment 12 – Jasper Fair Market Value.

(v) if a certain cost category was not reduced, as part of the adjustment to reflect the imprudent amounts associated with the sole-source Backwoods contract, to explain why a reduction was not necessary in each such case.

7.4 Does the $10.8 million reduction proposed by ATCO Electric reflect the full imprudent amount associated with the sole-source Backwoods contract?

157. ATCO Electric's 2018 MSA rates were obtained through a competitive request for proposal (RFP) process for a separate scope of access services work. This RFP was conducted at around the same time that construction activities were ramping up on the Jasper project.[135] ATCO Electric therefore asserted that its comparative rates analysis (of differences between the 2018 MSA rates and the actual rates paid to Backwoods) and the 2018 MSA rates together provide a reasonable (but not precise) indication of the rates that ATCO Electric could have obtained under a competitive bidding process for access services on the project.[136]

158. The Commission considers that ATCO Electric's reduction of $10.8 million is a reasonable starting point from which to determine the appropriate adjustment to the value of the sole-source Backwoods contract. However, the Commission finds that ATCO Electric's comparative rates analysis and the 2018 MSA rates are not determinative of reasonable amounts that ATCO Electric would have prudently incurred if it had competitively procured access services for the Jasper project. For the reasons that follow, the Commission has decided that it is reasonable to apply an additional reduction of 20 per cent to ATCO Electric's proposed reduction,[137] to ensure that ATCO Electric's access services costs reflect a reasonable proxy for the fair market value of prudent access services for the Jasper project.

Further adjustments are necessary to ATCO Electric's estimate

159. The Commission must estimate the prudent cost of access services for the Jasper project because ATCO Electric did not conduct a competitive bidding process to obtain access services. Instead, ATCO Electric chose to sole-source the access service contract for the Jasper project to Backwoods at rates that it knew were above fair market value. Therefore, the Commission does not have the benefit of analyzing: (i) rates that were obtained through a competitive process specific to the Jasper project; or (ii) work that would have been performed by a successful bidder to that competitive process on the Jasper project.

160. The Commission is put in the position of determining a counterfactual scenario. That scenario is: what are the amounts that ATCO Electric would have been charged for access services for the Jasper project if the access services had been obtained under a competitive process. This includes consideration of what rates would have been charged and how much ATCO Electric would have been billed. It also requires a consideration of whether the access services would have been contracted to one or more successful bidders for the various access services required (all of which ATCO Electric ultimately awarded to Backwoods). This counterfactual exercise is inherently imprecise, and while it is impossible to know what would

[135] Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF pages 106-109.
[136] Transcript, Volume 1 (January 25, 2023), page 12, lines 16-20, page 15, lines 14-22 and page 26, lines 1-11.
[137] ATCO Electric used $10.8 million as a proxy in its application for the imprudent amount associated with the sole-source Backwoods contract. That amount is subject to change in accordance with the Commission's directions set out in Section 7.3.

have happened with certainty, the Commission is charged with determining a reasonable amount for the access services, based on the record before it.

161. The counterfactual exercise does not shift ATCO Electric's burden. ATCO Electric bears the onus of establishing that the access services costs it has claimed in its amended application were prudently incurred.[138]

162. In its analysis, ATCO Electric explained that it did not review and compare detailed information from the Backwoods invoices to calculate the proposed reduction for access mat handling/movement and brushing/clearing costs. It opted instead to perform a high-level rate analysis using a simple average of the differences between Backwoods' labour and equipment rates from the Jasper project, and TerraPro's rates from the 2018 MSA, to calculate a percentage reduction for access mat handling/movement and brushing/clearing costs.[139]

163. The Commission finds that ATCO Electric's approach is flawed. ATCO Electric assigned equal weight to all labour and equipment categories, notwithstanding that the actual number of equipment and labour resources used on the Jasper project are known and not weighed equally. Furthermore, given that the contract value, and by extension the scope, of the 2018 MSA is significantly smaller compared to the Jasper project,[140] it is likely that the resource profile (number, composition and type of equipment and labour resources) used on the Jasper project differed when compared to the 2018 MSA.

164. The Commission is, however, of the view that ATCO Electric's comparative analysis and the 2018 MSA provides a workable, though not in all respects comparable, baseline for use as a starting point for the determination of prudent access services costs for the Jasper project. Based on the high-level and cursory nature of ATCO Electric's analysis, and given the importance of determining a reasonable amount for prudently incurred access services costs that will ultimately be borne by Alberta electricity customers, the Commission has, in the following sections, conducted its own analysis, which includes considerations not otherwise addressed by ATCO Electric. In particular, the Commission has assessed how access services rates would have differed from those under the competitively procured 2018 MSA, how volumes of access services work would have differed under a competitively procured contractor when compared to Backwoods, as well as the value that Backwoods brought to the Jasper project, in order to come to a reasonable estimate of above fair market costs incurred by ATCO Electric for access services.

Competitive rates and value

165. For the reasons that follow, the Commission's finds that the 2018 MSA rates are higher than rates that could reasonably have been obtained by ATCO Electric through a competitive

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[138] *Electric Utilities Act*, Section 121(4); Decision 2044-D01-2016: AltaLink Management Ltd., 2012 and 2013 Deferral Accounts Reconciliation Application, paragraphs 110-117; *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)*, 2015 SCC 45, paragraph 42.

[139] The details were provided on the confidential record: Exhibit 26573-X0310-C, Attachment 12 - Jasper Fair Market Value and Exhibit 26573-X0363-C, AET Responses to AUC Round 4 IRs, IR response AET-AUC-2022OCT21-006(b)-CONF.

[140] The details were provided on the confidential record: Exhibit 26573-X0348-C, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF pages 106-109.

RFP process for access services on the Jasper project, and that it is unclear what value Backwoods brought to the project.

166. First, the Commission agrees with the CCA, that ATCO Electric would have likely received a discount on the rates from a competitive RFP for access services for the Jasper project, compared to the rates from the 2018 MSA.[141] The contract value, and by extension the scope of the 2018 MSA, is significantly smaller compared to the Jasper project.[142] The 2018 MSA therefore does not reflect lower prices for a higher volume of work that would be expected on the Jasper project because of economies of scale. The access services rate analysis conducted by ATCO Electric's internal regulatory group agreed with this premise.[143] There were also examples of cases cited on the record of this proceeding where ATCO Electric received lower prices for higher volumes of materials[144] and received higher prices for lower volumes of access mats.[145]

167. Second, some contractors provided more competitive access mat rental rates, while others provided more competitive labour rates.[146] This prompted the Commission to ask ATCO Electric whether it would have been more cost-efficient to segment the access services scope of work (i.e., renting access mats, access mat handling services, brushing/clearing, etc.) by awarding different contracts with different work scopes to different access services providers (based on the competitiveness of their rates).

168. ATCO Electric conceded that historically, on previous projects, brushing/clearing and access maintenance contracts have been tendered separately from access matting services (supply and movement) contracts, and awarded to separate parties. It also explained that there were limited instances where different aspects of the access matting scope were contracted to different entities, but that it was more common for the brushing/clearing scope of work to be treated separately. However, for the Jasper project, ATCO Electric contended that it would not necessarily have been more efficient to award different scopes of access services work to different contractors (and thereby use multiple contractors), given the constraints of the ROW on the Jasper project. It explained that: (i) these constraints drove a desire to minimize the number of parties working on the ROW, to control physical traffic; and (ii) running additional contractors in this narrow ROW, with multiple work fronts, would further complicate line construction activities.

169. The Commission observes that ATCO Electric's position appears to be contradicted by the fact that ATCO Electric did use multiple access services contractors on the Jasper project: TerraPro (as a subcontractor to Backwoods) for the access matting scope of work; and Backwoods for the brushing/clearing scope of work. ATCO Electric also maintained that Backwoods did not cause any inefficiencies. Therefore, it is unclear to the Commission why the

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[141] Transcript, Volume 1 (January 25, 2023), page 89, lines 16-24.
[142] The details were provided on the confidential record: Exhibit 26573-X0348-C, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF pages 106-109.
[143] Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF page 65-68.
[144] Exhibit 26573-X0410, 26573 CCA responses to AUC IR Round 2 CONF Unredacted, IR response CCA-AUC-2022DEC19-001(a), PDF page 3.
[145] The details were provided on the confidential record: Exhibit 26573-X0368-C, AET-AUC-2022OCT21-007(k) Attachment 1.
[146] The details were provided on the confidential record: Exhibit 26573-X0313-C, Attachment 15 – Exhibit 27013-X0082-C Tab 14 - 2018 Matting MSA Bid Rates.

different scopes of access services work could not have been segmented and awarded to different contractors, based on the price competitiveness of their rates.

170. Ultimately, had the access services work been competitively tendered, the Commission is of the view that it is reasonable to believe that, depending on the bids received, multiple awards could have been made to separate contractors based on bid criteria, including experience, estimates of work volume and rates. The opportunity to do so was forgone on the Jasper project as a result of the decision to sole-source the access services contract to Backwoods. For this reason, the Commission finds that further cost savings could have been realized with a market-based contract that are not accounted for in ATCO Electric's proposed $10.8 million reduction.

171. Third, the Commission is not persuaded that Backwoods added value to the performance of the access matting scope of work, in its capacity as the manager of this work.

172. ATCO Electric sole-sourced the access services contract for the Jasper project to Backwoods. Multiple parties from ATCO Electric expressed concerns with Backwoods' inexperience in terms of the access matting scope of work required to be completed on the Jasper project.[147] ATCO Electric's own regulatory group stated that "adopting this structure to provide these service with a vendor who does not have the experience to provide these services will result in a higher overall project cost."[148]

173. Backwoods subsequently subcontracted all of the access matting (including access mat rentals and mat handling/movement) work to TerraPro,[149] a large, experienced matting and earthworks contractor with 14 offices across Western Canada, approximately 100,000 access mats in their inventory and 2,800 completed projects since its inception in 2006.[150]

174. After the access matting scope of work was subcontracted to TerraPro, ATCO Electric explained that Backwoods was primarily accountable for the commercial project and construction management activities of their contract scope, including managing subcontractors.[151]

175. It is well established on the record of this proceeding that Backwoods lacked experience in delivering the very services that it was contracted by ATCO Electric to provide. This is supported by the concerns expressed by ATCO Electric's own regulatory group with respect to Backwoods' experience and the associated project costs, and the lack of a competitive RFP process to confirm that Backwoods was qualified to manage the access services scope of work for a project where there was "a winding, narrow ROW with limited access points, mountainous and rocky terrain, uncertain and evolving Parks Canada requirements, and working in proximity to major transmission pipelines and rail lines."[152] The Commission therefore finds it reasonable

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147 Exhibit 26573-X0349, 27013-X0053.01-C Appendix F - Documents provided to Enforcement Staff by ATCO Electric during the Investigation, PDF page 35, paragraph 18; Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF pages 2 and 67.

148 Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff, PDF page 67.

149 Exhibit 26573-X0346, 27013-X0069 Settlement Agreement and Agreed Statement of Facts, PDF page 31, paragraph 110.

150 Exhibit 26573-X0346, 27013-X0069 Settlement Agreement and Agreed Statement of Facts, PDF page 18, paragraph 26.

151 Exhibit 26573-X0416, AET Round 2 Rebuttal Evidence, PDF page 11, paragraph 23.

152 Transcript, Volume 1 (January 25, 2023), page 17, lines 19-25.

to conclude that Backwoods' ability to manage issues or challenges arising throughout the project would not compare favourably to a more experienced vendor or vendors addressing the same issues or challenges. It follows that the volume of work required by Backwoods to address the issues and challenges arising on the Jasper project would reasonably be expected to be higher than would be the case for a seasoned vendor with a greater level of experience and expertise. As such, the Commission concludes that the work completed and the inefficiencies created by using Backwoods, a relatively inexperienced vendor, increased the costs compared to the costs that would have been incurred had a competitively procured and more experienced contractor been awarded the work, as was the case under the 2018 MSA.

176. It is also unclear to the Commission what value Backwoods brought to the matting scope of work. Backwoods subcontracted the access matting scope of work to TerraPro, a highly experienced access services contactor. TerraPro attended the plan-of-the-day meetings, which ATCO Electric described as follows:[153]

> Plan of the day meetings were held at the field level between AET and ROW contractors where directions were given to ROW contractor to deliver and lay down mats at the planned tower site locations. The Field teams meeting would occur first thing in the morning followed by an internal Project Management meeting to communicate the plan. The discussion would focus on the daily activities, go-forward activities, and any issues and mitigation efforts ongoing to efficiently plan and progress construction.
>
> The line construction contractor provided the Construction team with detailed planning schedules. The information was then communicated to the entire team at the Plan of the day meetings. This information was used to coordinate mat requirements with the matting contractor to support construction activities and provide access to, and use of, the work site locations.

177. The line contractor and ATCO Electric appear to have provided direction and instruction on matting requirements during the plan-of-the-day meetings, and TerraPro was directly involved in these meetings. Furthermore, given the difference in experience between TerraPro and Backwoods, the Commission is not persuaded that Backwoods could have provided any incremental support or insight that TerraPro would not already have had and been able to provide to the line contractor, on how to manage the access mats. The Commission is therefore of the view that the value Backwoods brought to the Jasper project was not established by ATCO Electric.

178. In view of the above, and understanding that the Commission cannot observe directly applicable market rates, because it is considering a counterfactual scenario, the Commission has decided that it is reasonable to apply an additional reduction of 20 per cent to ATCO Electric's proposed reduction. ATCO Electric proposed a $10.8 million reduction in its application; however, given the uncertainty in the total value of the Backwoods contract (as set out in Section 7.3), the Commission directs ATCO Electric to calculate this additional 20 per cent reduction in accordance with Appendix 3. The Commission considers that this additional reduction reasonably reflects the incremental imprudent costs that the Commission has decided are not otherwise captured in ATCO Electric's currently proposed $10.8 million reduction.

[153] Exhibit 26573-X0358, AET Responses to AUC Round 4 IRs, IR response AET-AUC-2022OCT21-010(a), PDF page 60; and Exhibit 26573-X0401, 26573 CCA Evidence - AET Proposed Redactions, PDF page 9, paragraph 20(m).

7.5 What costs were incurred by ATCO Electric for work conducted in an effort to mislead and conceal information associated with the sole-source Backwoods contract?

179. In the Commission's September 20, 2022, letter reopening the proceeding,[154] it indicated that this proceeding would test "costs related to efforts to mislead and conceal critical information" related to the Backwoods contract. ATCO Electric estimated that these costs were $13,675.[155] [156] The CCA contended that these costs amounted to $818,000.[157]

180. For the reasons that follow, the Commission has decided that $250,000 is a reasonable estimate of costs related to efforts to mislead and conceal critical information.

181. ATCO Electric contended that this category of imprudent costs should only include costs connected to activities undertaken by individuals with knowledge that their activities would mislead or conceal information.[158] ATCO Electric focused on the word "efforts" used by the Commission in reopening the scope of this proceeding and argued that the definition of the word "efforts" implies knowledge or, at the very least, an understanding of an overall objective. It further indicated that the "vast majority" of individuals involved in the execution of the project and preparation of the 2018-2020 DACDA application did not have knowledge of the underlying circumstances or the objective of avoiding detection.

182. The Commission does not accept ATCO Electric's interpretation. That interpretation focuses on one word from the Commission's reopening letter (i.e., "efforts,") while minimizing the context in which that word appears. The Commission's reopening letter made clear it was examining "costs related" to "efforts" to "mislead and conceal" in this proceeding. In the Commission's view, costs related to efforts to mislead and conceal include costs connected to work undertaken, whether knowingly or unknowingly, in furtherance of misleading or concealing information related to ATCO Electric's actions. It is the prudency of costs connected to the conduct, rather than whether the conduct, or "effort" was undertaken knowingly in furtherance of an illicit objective that is at issue. Ultimately, it is neither fair nor reasonable for Alberta electricity customers to pay, through their rates, for costs incurred to perpetuate a lie, whether knowingly or not.

183. ATCO Electric's cost estimate of $13,675 is significantly understated because in preparing it, ATCO Electric assumed that an individual had to be aware of the circumstances surrounding the Backwoods access services contract, in order for the costs connected with imprudent activities that individual performed to be included in its estimate. Because of this assumption, ATCO Electric's estimate did not include costs related to multiple imprudent activities that would not have been required, but for the Backwoods access services contract. For example, ATCO Electric did not include the costs of:

[154] Exhibit 26573-X0332, AUC letter - Scope of Proceeding 26573 and process schedule.
[155] Exhibit 26573-X0358, AET Responses to AUC Round 4 IRs, IR responses AET-AUC-2022OCT21-011 and AET-AUC-2022OCT21-012.
[156] Transcript, Volume 1, (January 25, 2023), page 12, lines 21-24.
[157] Transcript, Volume 1, (January 25, 2023), page 82, lines 14-18.
[158] Transcript, Volume 1, (January 25, 2023), pages 41-42.

(i) Analyses that were undertaken to calculate the regulatory risk associated with the sole-source Backwoods contract.[159]

(ii) Negotiations with Backwoods to bring its rates closer to fair market value,[160] which would not have been necessary if ATCO Electric procured its access services through a competitive bidding process.

(iii) Conversations, meetings and other work conducted to justify and defend its decision to imprudently sole-source the access services contract to Backwoods.

(iv) Documenting a false record, including drafting and providing misleading information in the original 2018-2020 DACDA application and this proceeding, etc.[161]

None of this work would have been required had the truth been told from the outset.

184. The true scope of this work cannot be ascertained on the record of this proceeding. ATCO Electric took the position that knowledge is required for an individual to mislead or conceal. Also, ATCO Electric did not provide a cost estimate (including data on individuals involved, their hourly rates, the amount of time spent on each activity, etc.) for all of the imprudent activities that were undertaken (e.g., research and analysis conducted by ATCO Electric's forestry team around fair market rates).[162]

185. Furthermore, the Commission does not agree with ATCO Electric's submission, that a vast majority of the 2018-2020 DACDA application support costs would have been incurred regardless of how the access services were procured. ATCO Electric's submission implies that there is a one-to-one relationship between the activities that were undertaken to support the Backwoods contract and the activities that would have been undertaken had the access services been competitively procured.[163]

186. In the Commission's view, it is inherently more time consuming to mislead and conceal than it is to simply state the truth. This is the case for the contracting work itself, but is particularly true in the context of a regulatory proceeding where an application, evidence, IR responses and rebuttal evidence are prepared and necessarily approved by the relevant executives within ATCO Electric prior to being filed with the Commission. The Commission is cognizant of the level of effort expended on a typical DACDA application and considers that such effort would increase significantly where some, but not all, ATCO Electric employees involved in the preparation of this material were working to conceal or create misleading evidence. Merely

[159] Example: Decision 27013-D01-2022, PDF page 14, paragraph 49(5).
[160] Activities identified in Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff; and Exhibit 26573-X0349, 27013-X0053.01-C Appendix F - Documents provided to Enforcement Staff by ATCO Electric during the Investigation.
[161] Activities identified in Exhibit 26573-X0348, 26573-X0317 Attachment 19 - Exhibit 27013-X0035, Appendix A - Documents provided to Enforcement Staff; and Exhibit 26573-X0349, 27013-X0053.01-C Appendix F - Documents provided to Enforcement Staff by ATCO Electric during the Investigation.
[162] The details were filed on the confidential record: Exhibit 26573-X0378-C, AET-AUC-2022OCT21-011(a) Attachment 1; Exhibit 26573-X0316-C, Attachment 18 – Exhibit 27013-X0127-C Tab 15 – Forestry Team Research.
[163] Transcript, Volume 1 (January 25, 2023), pages 46-57.

tracking who is aware of the need to cover up the truth and who is not, would have created additional work and a high degree of inefficiency.

187. In Decision 27013-D01-2022 the Commission addressed the (then paused) DACDA proceeding directly, indicating that approximately 45 ATCO Electric employees were involved, most of whom were not aware of the events surrounding the decision to directly award the Backwoods contract.[164] Decision 27013-D01-2022 also spoke to the false evidence provided and the omissions deliberately made. As the CCA analysis shows, some detailed information can also be gleaned from the Settlement Agreement and Agreed Statement of Facts and Contraventions.[165] Ultimately, however, only ATCO Electric knows with any certainty the costs related with efforts to mislead and conceal in relation to the Backwoods contract and the associated issues in the 2018-2020 DACDA proceeding and it has not been particularly forthcoming in this regard.

188. While the Commission has some information about the imprudent work that was undertaken on the Jasper project with respect to the issuance of the Backwoods contract (e.g., ATCO Electric had to prepare briefings, analyses, the 2018 requisition enhancement form, etc., in order to justify and defend its decision to contract with Backwoods) and the associated costs,[166] there is limited information about the work that was undertaken to support the Jasper project in ATCO Electric's 2018-2020 DACDA application. In this regard, the Commission observes that the Jasper project was the largest issue in ATCO Electric's 2018-2020 DACDA application and expects that ATCO Electric would therefore have devoted a significant amount of time to support this aspect of its application when compared to other areas.

189. The Commission must rely on information that is on the record to inform an estimate for what it considers to be a reasonable amount attributable to efforts to mislead and conceal. While the CCA's effort to develop its own estimate was helpful in the sense that the results of that analysis provided one possible bookend for the Commission's consideration, the assumptions that were necessarily required to be made, given the significant information asymmetry in this regard, weakened the analysis and compromised the Commission's ability to rely on this estimate. The CCA itself acknowledged that its proposal was imprecise[167] and reduced the amount of its proposed disallowance significantly at the time of argument.[168]

190. Without a much higher degree of cooperation, effort, and transparency from ATCO Electric on this issue, it is not possible for the Commission to develop a precise estimate. ATCO Electric did not provide an estimate of the number of individuals who were assigned to support the Jasper project. It attempted to provide this information in reply argument,[169] but the Commission did not permit this information to be filed on the proceeding record so late in the hearing process.[170]

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164 Decision 27013-D01-2022, PDF pages 13 and 60-61, paragraphs 47 and 118-119.
165 The details were filed on the confidential record: Exhibit 26573-X0429-C, Exhibit 26573-X0409.01-C 26573-X0403.01-C Attachment 2 - Costs of Investigations and Efforts to Mislead.
166 The details were filed on the confidential record: Exhibit 26573-X0378-C, AET-AUC-2022OCT21-011(a) Attachment 1; Exhibit 26573-X0381-C, AET-CCA-2022OCT21-006(a)-CONF Attachment 1. See also Exhibit 26573-X0346, 27013-X0069 Settlement Agreement and Agreed Statement of Facts.
167 Transcript, Volume 2 (January 26, 2023), page 41, lines 15-25.
168 Transcript, Volume 1 (January 25, 2023), page 82, lines 14-18.
169 Transcript, Volume 2 (January 26, 2023), pages 62-70.
170 Transcript, Volume 2 (January 26, 2023), page 71, lines 1-10.

191. As a result, and to determine a reasonable estimate grounded in the facts, the Commission has considered the following:

(i) Available information about efforts to mislead and conceal concerning the imprudent contracting work that was undertaken on the Jasper project,[171] including descriptions of this work in the Agreed Statement of Facts and Contraventions from Proceeding 27013;[172]

(ii) The duration that the 2018-2020 DACDA proceeding was active, provision for an expected period of preparation as well as for work spent on the Backwoods contract itself, all of which would have been charged to the Jasper project;

(iii) The significance of the Jasper project to the 2018-2020 DACDA proceeding and ATCO Electric's 2018-2020 DACDA application;

(iv) The starting point that approximately 45 employees were involved in the application (as stated in Decision 27013-D01-2022);

(v) Acknowledgement that not all 45 employees would have worked on the Jasper project aspects of the DACDA and that of those that would have dedicated time to it, that work was unlikely to be full time during the period of preparing the application and when the proceeding was active;

(vi) Acknowledgment that of the time spent on the Jasper project, only a fraction would have been either knowingly or unknowingly expended in an effort to mislead and conceal information from the Commission; and

(vii) Taking a conservatively low average of the charge out rates for employees working on the matter.

192. Based on this admittedly high level and deliberately conservative analysis, the Commission has decided that $250,000 in imprudently incurred costs related to efforts by ATCO Electric employees to mislead and conceal information should be disallowed from the applied-for costs for the Jasper project.

193. Accordingly, the Commission directs ATCO Electric to reduce its applied-for costs for the Jasper project by $250,000 in its compliance filing to this decision. This reduction is incremental to the other reductions and disallowances that the Commission has directed in this decision. This is, in the Commission's view, an understated, but nevertheless reasonable disallowance in the circumstances of this proceeding.

194. The Commission emphasizes that in coming to this disallowance amount, the intention is to remove imprudent costs actually incurred in relation to the work conducted on, and in relation to, the Jasper project. The Commission's cautious approach, given imperfect information, is intended to balance the need to ensure that Alberta electricity customers are not paying through

[171] The details were filed on the confidential record: Exhibit 26573-X0378-C, AET-AUC-2022OCT21-011(a) Attachment 1; Exhibit 26573-X0381-C, AET-CCA-2022OCT21-006(a)-CONF Attachment 1; and Exhibit 26573-X0429-C, Exhibit 26573-X0409.01-C 26573-X0403.01-C Attachment 2 - Costs of Investigations and Efforts to Mislead.

[172] Exhibit 26573-X0346, 27013-X0069 Settlement Agreement and Agreed Statement of Facts.

their rates for ATCO Electric's imprudence, with the need to provide ATCO Electric a reasonable opportunity to recover its prudently incurred costs.

7.6 Should ATCO Electric be directed to track actions and costs related to its implementation of the settlement agreement concerning the Jasper project?

195. The Office of the Utilities Consumers Advocate (UCA) requested that the Commission direct ATCO Electric to directly track all actions and costs related to its implementation of the settlement agreement concerning the Jasper project, and to include that information in its Rule 005 filings.[173] ATCO Electric agreed to provide this information in its Rule 005 filings.[174] Accordingly, the Commission directs ATCO Electric to include the information requested by the UCA in its Rule 005 filings.

8 Order

196. It is hereby ordered that:

(1) ATCO Electric submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before May 29, 2023; provided, however, that ATCO Electric is not required to submit such a compliance filing if the Commission orders a compliance filing for ATCO Electric's 2023-2025 general tariff application in Proceeding 27062. In such a case, ATCO Electric is ordered to incorporate the findings, conclusions and directions of the Commission in this decision together with its compliance filing to the Commission's decision in Proceeding 27062.

Dated on April 26, 2023.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Vice-Chair

[173] Transcript, Volume 1 (January 25, 2023), page 125, lines 3-11.
[174] Exhibit 26573-X0361, AET Responses to UCA Round 4 IRs.

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
Consumers' Coalition of Alberta (CCA) Bema Enterprises Ltd.
Office of the Utilities Consumers Advocate (UCA) Brownlee LLP InterGroup Consultants

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair Commission staff P. Khan (Commission counsel) N. Bal (Commission counsel) A. Starkov L. Mullen C. Meulenbroek

Appendix 2 – Virtual oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative
ATCO Electric Ltd. (ATCO Electric) Sean Assié
Consumers' Coalition of Alberta (CCA) James Wachowich, KC
Office of the Utilities Consumer Advocate (UCA) Thomas Marriott, KC Keegan Rutherford

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair Commission staff P. Khan (Commission counsel) N. Bal (Commission counsel) A. Starkov

Appendix 3 – Commission directions on reductions to the Jasper project

(return to text)

Appendix 3.1 – Commission-directed clarification on the value of the sole-source Backwoods contract

Item	Total value of the Backwoods contract ($ million)	Commission-directed clarifications for the value of the sole-source Backwoods contract	Reference to decision section and paragraph
What is the total value of the Backwoods contract? There are three sources of information that indicate different amounts paid to Backwoods			
(1)	31.1 + 2.1 = 33.2	From the Agreed Statement of Facts made between ATCO Electric and AUC Enforcement staff. That instrument indicates that the total amount ultimately paid to Backwoods was $31.1 million for matting-related work and $2.1 million for brushing/clearing-related work.	Section 7.3, paragraph 151
(2)	36.7	From the breakdown filed by ATCO Electric that shows the initial value of the Backwoods contract, and subsequent change orders.	Section 7.3, paragraph 154
(3)	35.3 to 37	From the Executive Summary of ATCO Corporate Security's investigative report, which indicated that the final award to Backwoods was in the amount of $35,305,889. It also noted that ATCO Electric claimed, in its 2018-2020 DACDA application, $37 million for the Backwoods direct award contract.	Section 7.3, paragraph 154
(4)	TBD	ATCO Electric confirmation of the total value of the Backwoods contract.	Section 7.3, paragraph 156

Appendix 3.2 – Commission-directed clarification on applied-for reduction for imprudent amount associated with the sole-source Backwoods contract

Item	Applied for reduction ($ million)	Commission-directed clarifications on applied-for reduction to sole-source Backwoods contract	Reference to decision section and paragraph
Applied-for reduction for imprudent amounts associated with the sole-source Backwoods contract			
(5)	10.8	ATCO Electric determined the $10.8 million reduction by using the differences between: (i) the actual rates paid to Backwoods on the Jasper project; and (ii) the rates from ATCO Electric's 2018 Master Service Agreement. At a high level, ATCO Electric then applied the differences to the total value of the Backwoods contract.	Section 7.3, paragraph 145
(6) which is dependent on (4)	TBD	ATCO Electric confirmation of its applied-for reduction for imprudent amounts associated with the sole-source Backwoods contract, which is dependent on the total value of the Backwoods contract.	Section 7.3, paragraph 156

Appendix 3.3 – Commission-directed additional reduction for imprudent amount associated with the sole-source Backwoods contract

Item	Directed additional reduction ($ million)	Commission-directed additional reduction for imprudent amount associated with the sole-source Backwoods contract	Reference to decision section and paragraph
Directed reduction for imprudent amounts associated with the sole-source Backwoods contract			
(7) = (6) x 20 per cent	TBD	The Commission has decided that it is reasonable to apply an additional reduction of 20 per cent to the imprudent amount associated with the sole-source Backwoods contract. This reduction amount is dependent on the clarifications directed in the above appendixes.	Section 7.4, paragraph 178

Appendix 3.4 – Summary of Commission-directed reductions for the Jasper project

Item	Amount of reduction ($ million)	Commission-directed reductions	Reference to decision section and paragraph
Directed reduction for imprudent management and execution of the Jasper project			
(8)	3.0	ATCO Electric's imprudent management and execution of the consultation, permitting, regulatory and approval phases of the Jasper project. This amount will not be adjusted in the compliance filing.	Section 7.1, paragraph 132
Directed reduction for work conducted in effort to mislead and conceal information associated with the sole-source Backwoods contract			
(9)	0.250	Disallowance for work conducted in effort to mislead and conceal information associated with the sole-source Backwoods contract. This amount will not be adjusted in the compliance filing.	Section 7.5, paragraph 193
Directed additional reduction for imprudent amount associated with the sole-source Backwoods contract			
(10) = (7)	TBD	The Commission has decided that it is reasonable to apply an additional reduction of 20 per cent to the imprudent amount associated with the sole-source Backwoods contract. This reduction amount is dependent on the clarifications directed in the appendixes above.	Section 7.4, paragraph 178
(11) = (8)+(9)+(10)	TBD	Total Commission-directed reductions for Jasper project	

Appendix 4 – Summary of Commission directions addressed in application

(return to text)

This section is provided for the convenience of readers and outlines the directions from Decision 2013-358 (ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application), Decision 2014-283 (ATCO Electric Ltd., 2012 Transmission Deferral Account and Annual Filing for Adjustment Balances), Decision 21206-D01-2017 (ATCO Electric Ltd., 2013 and 2014 Transmission Deferral Accounts and Annual Filing for Adjustment Balances) and Decision 24375-D01-2020 (ATCO Electric Ltd., Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances) and which the Commission finds have been satisfied. In the event of any difference between the directions in this section and those in the main body of the decisions referenced, the wording in the main body of those decisions shall prevail.

Decision 2013-358 (Direction 92)

92. The Commission directs ATCO Electric, in its next transmission GTA and next annual transmission deferral account application, to include the following additional information with respect to any individual direct assigned capital project that has a forecast capital cost in excess of $5.0 million:

- project milestone schedules and the timing of capital expenditures
- AESO change order requests and authorizations
- cost estimates at the stages described in paragraph 1082 of this decision
- cost estimates by the categories described in paragraph 1084 of this decision
- the preliminary engineering costs included in the cost estimates
- the detailed engineering costs included in the cost estimates
- schedules of project attributes, for both transmission line projects and substation projects, similar to the information provided in response to information request IPCAA-AE-008(c)
- parametric values that are derived through the use of parametric estimating techniques
- the current AESO functional specifications
- bulk transmission line optimization studies where required by ISO Rule 502.2
- post completion reports
- 60-day and 150-day reports that are filed in response to the AESO's rules ..... Paragraph 1096

Decision 2014-283 (directions 1, 2, 3, 4 and 21)

1. Of particular concern is that the information provided with ATCO's original filing did not include a clear breakdown of the original cost estimate for the portion of certain projects it was requesting to be added to rate base in 2012. Most notably, ATCO's initial filing did not provide any estimate of the baseline cost estimate for the portion of the NE Loop project to be added in 2012, subsequently clarified to be the 9L84 segment of the project from the Salt Creek 977S substation to the Black Fly 934S substation, compared to the actual costs to be added in 2012. The Commission considers that the initial cost breakdown that ATCO provided in attachment 1 of its application, which suggested that

the requested 2012 addition amount of $229.2 million compared favourably to the PPS stage estimate of $237.4 million for the entire project, was misleading and contributed to the additional process required to examine the application. In light of this issue, in all future capital deferral account applications, ATCO is directed to ensure that the PPS stage estimates it provides are properly matched to the specific facilities it is proposing for inclusion in rate base in that year. ..... Paragraph 102

2. Further to the findings in Section 2.1.2 above that a key purpose of baseline estimates is to assist in drawing attention to variances requiring additional investigation, the Commission directs ATCO to provide the following in all future applications:

   - a detailed breakdown of PPS format cost estimates or reports that have been prepared at each of the PPS stages, and at the 180-day after the permit and licence stage
   - any final cost report prepared after energization
   - the details of owner costs and distributed cost line items that were supplied through information requests in this proceeding. ..... Paragraph 103

3. ATCO is directed to file the above-noted cost breakdown information, accessible in a useable electronic format, such as excel, in all its future capital deferral account filings. ..... Paragraph 104

4. A final concern identified by the Commission during its initial review of the application related to its difficulty in matching the project names and related numbers used by ATCO to project naming conventions used in other proceedings. It is essential that the Commission and parties be able to clearly understand what specific facilities were contemplated at the time project forecasts were provided at various project development stages. Consequently, ATCO is directed to provide information that is sufficient to clearly match the projects for which capital additions are requested to the facility application, the NID application, and all associated decisions, including the specific permits and licences issued. Furthermore, in the event that the functional specification or scope of a specific project is changed for any reason subsequent to the issuance of the permit and licence, ATCO is directed to provide a clear explanation of both the nature and timing of the changes that have occurred..... Paragraph 105

21. However, the Commission remains concerned with the limited information provided by ATCO in its initial application. To address this concern, ATCO is directed to provide both a breakdown of applied-for trailing cost addition amounts in a substantially similar format to the breakdown provided in CCA-AE-18, Attachment 1, and to also provide explanations of trailing costs in a format equivalent to that provided in ATCO's response to CCA-AE-18, part (b) for all future direct assigned transmission project deferral account reconciliation applications. ..... Paragraph 801

Decision 21206-D01-2017 (directions 11 and 12)

11. Nonetheless, to properly assess the final project costs, the Commission considers that in order to balance the Commission's concerns with respect to accruals while allowing ATCO Electric to recover all prudently incurred project costs in a fiscal year, it will not direct ATCO Electric to remove any accrued costs from its applied-for capital additions

but will direct ATCO Electric to file certain additional information in future applications. The Commission directs ATCO Electric to clearly identify and explain accrual amounts included in applied-for project capital additions for all future deferral account applications. The Commission also directs ATCO Electric to clearly identify all trailing costs that resulted from reconciling accrued amounts to actual final costs, in all future deferral account applications; this can be provided in a similar format to that provided in Table 2-8 in this application. ..... Paragraph 234

12. With respect to filing requirements, as set out in Direction 1 from Decision 2011-507, Direction 92 from Decision 2013-358 and directions 1, 2, 3, 4 and 21 from Decision 2014-283 and in the additional information provided as outlined in Tables 2-6 and 2-7 of the application, the Commission finds that the level of detail provided for the requested project capital additions was helpful in its consideration of this application and therefore directs ATCO Electric to file this information in all future DACDAs.
..... Paragraph 243

Decision 24375-D01-2020 (directions 5 and 12)

5. The Commission also accepts AET's proposal to true up this $0.1 million of foundation materials in a subsequent deferral application. For the purposes of this application, the Commission accepts that the $0.1 million of foundation materials incurred for Project 55127 are reasonable and will allow AET to recover this cost in full. The Commission directs AET to correct for this error in its future deferral applications.
.....paragraph 91

12. Therefore, the Commission directs AET, as part of its next DACDA application, to fully document and explain the internal processes used to determine when external legal resources are required, to establish the scope of the work to be performed by those resources, and to provide demonstrative examples for small, medium and large projects.
.....paragraph 330

Appendix 5 – 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 requires ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before May 29, 2023; provided, however, that ATCO Electric is not required to submit such a compliance filing if the Commission orders a compliance filing for ATCO Electric's 2023-2025 general tariff application in Proceeding 27062. In such a case, the Commission directs ATCO Electric to incorporate the findings, conclusions and directions of the Commission in this decision together with its compliance filing to the Commission's decision in Proceeding 27062. ..... paragraph 11

2. With respect to Direction 7 requiring ATCO Electric to ensure air travel costs are charged at no more than commercial airlines economy fare, ATCO Electric stated that an applicable adjustment had not been incorporated into its application on the basis that the amount at issue is immaterial. The Commission finds that ATCO Electric has not complied with this direction. The Commission further directs ATCO Electric to reduce its applied-for costs by $11,267 in its compliance filing to this decision..... paragraph 29

3. For all of these reasons, the Commission denies ATCO Electric's proposed recovery of the $4.381 million amount it sought under the pretense of cancelled customer project costs. The Commission directs ATCO Electric to reduce its applied-for costs by $4.381 million in its compliance filing to this decision. ..... paragraph 71

4. Accordingly, the Commission directs ATCO Electric to reduce its applied-for costs for the Jasper project by $3.0 million in its compliance filing to this decision, which represents approximately three per cent of the current total applied-for project costs and approximately 14 per cent of the variance between PPS forecast and actual applied-for project costs. The Commission notes that this disallowance includes amounts for the disallowance attributed to its findings in Section 7.2.3 of this decision provided below. ..... paragraph 132

5. Given this lack of clarity, the Commission directs ATCO Electric, in its compliance filing to this decision:

   (i) to explain the inconsistencies identified above in the total value of the amounts incurred under the Backwoods contract;

   (ii) to confirm the total amount that ATCO Electric is requesting approval to recover for the Backwoods direct award contract in its 2018-2021 DACDA application;

   (iii) to provide a breakdown of the amount in subpart (ii) by cost category (mat rentals, mat purchases, mat movement, mat cleaning, brushing/clearing, hydrovac, etc.);

   (iv) to confirm that ATCO Electric applied the appropriate and necessary adjustments (i.e., consistent with the methodology that it used to calculate its currently proposed $10.8 million reduction) to each cost category from part (iii), by reducing the imprudent amounts associated with the sole-source Backwoods contract; and

(v) if a certain cost category was not reduced, as part of the adjustment to reflect the imprudent amounts associated with the sole-source Backwoods contract, to explain why a reduction was not necessary in each such case. ..... paragraph 156

6. In view of the above, and understanding that the Commission cannot observe directly applicable market rates, because it is considering a counterfactual scenario, the Commission has decided that it is reasonable to apply an additional reduction of 20 per cent to ATCO Electric's proposed reduction. ATCO Electric proposed a $10.8 million reduction in its application; however, given the uncertainty in the total value of the Backwoods contract (as set out in Section 7.3), the Commission directs ATCO Electric to calculate this additional 20 per cent reduction in accordance with Appendix 3. The Commission considers that this additional reduction reasonably reflects the incremental imprudent costs that the Commission has decided are not otherwise captured in ATCO Electric's currently proposed $10.8 million reduction. ..... paragraph 178

7. Accordingly, the Commission directs ATCO Electric to reduce its applied-for costs for the Jasper project by $250,000 in its compliance filing to this decision. This reduction is incremental to the other reductions and disallowances that the Commission has directed in this decision. This is, in the Commission's view, an understated, but nevertheless reasonable disallowance in the circumstances of this proceeding. ..... paragraph 193

8. The Office of the Utilities Consumers Advocate (UCA) requested that the Commission direct ATCO Electric to directly track all actions and costs related to its implementation of the settlement agreement concerning the Jasper project, and to include that information in its Rule 005 filings. ATCO Electric agreed to provide this information in its Rule 005 filings. Accordingly, the Commission directs ATCO Electric to include the information requested by the UCA in its Rule 005 filings. ..... paragraph 195

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 6:

By J. Massie to G. Bentivegna

PDF p. 20, lines 22-25 and PDF p. 21, lines 1-2

> J. MASSIE: So I -- we could take it away to undertake to provide what that total was in 2022 if that's a little insufficient for the board's needs.
>
> G. BENTIVEGNA: Certainly. That would be useful. So my understanding of your undertaking is you'll provide the 2022 actuals.

Response:

AEY's actual FTEs for 2022 and continuity to applied for 2023 FTEs are as follows:

Table 1: FTEs

2022 Actual FTE		**68.80**
2022 Vacancies		*3.31*
2023 Addition – Mgr. Renewables & Grid Mod	Hired Jun. 2023	*1.00*
2023 Addition – Team Lead Plant	Recruiting	*1.00*
2023 Addition – Electrical Engineer	Recruiting	*1.00*
2023 Addition – Finance	Hired Dec. 2022	*0.50*
2023 Addition – Regulatory	Hired Dec. 2022	*0.25*
2023 Addition – Government Relations	Hired Jul. 2023	*0.40*
2023 Applied FTE*		**76.26**

*AEY applied the 5-year average vacancy rate to the 2023 FTE to reduce the overall labour forecast included in revenue requirement.

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 9:

By J. Massie to G. Bentivegna
PDF p. 68, lines 17-25 and PDF p. 69, lines 1-23

G. BENTIVEGNA: Certainly. Just -- just to ensure that we understand whether the temperature -- low temperatures are -- that low a temperature will be a problem for these meters and whether that's been looked at.

Now, just to get an understanding of comparing what AEY's costs are for meter readings currently and the difference with not having to read meters manually, would you be able to tell us what the cost of reading meters is in the following areas -- and I'm -- if you

don't have this at hand, certainly an undertaking. On Mayo Road, Carmacks, Carcross Road, Carcross/Tagish, Marsh Lake and Teslin.

J. MASSIE: Yeah. We will certainly have to undertake to provide the costs. I can tell you from my days of reading meters out there that it is a full day to go to Tagish to read all the meters and back, and there's a couple days that are spent between the Carcross Road, Carcross/Tagish, Marsh Lake. There are a number of days. But we can undertake to provide that.

G. BENTIVEGNA: Thank you.

B. ROGERS: May I ask you to repeat those communities just so our team that's supporting us can get working on that.

G. BENTIVEGNA: Sure. That was -- sorry. I'm just going to find it. That was Mayo Road, Carmacks, Carcross Road, Carcross/Tagish, Marsh Lake, and Teslin.

B. ROGERS: Thank you.

J. MASSIE: And just for the utmost clarity, I assume it's just how many hours or -- I guess the overall cost, labour cost of going out there to read meters?

G. BENTIVEGNA: Yes, the overall costs, labour costs. That would be useful. Thank you.

Response:

Please refer to Table 1 below for the forecast meter reading costs by community.

Table 1: 2023 Forecast Meter Reading Costs by Community

Location	Hours to Read Monthly	Cost per Hour ($)	Monthly Cost ($)	Annual Cost ($)
Mayo Road	33	120	3,960	47,520
Carmacks	15	120	1,800	21,600
Carcross/Carcross Rd	32	120	3,840	46,080
Tagish/Tagish Rd	24	120	2,880	34,560
Marsh Lake	24	120	2,880	34,560
Teslin	15	120	1,800	21,600
Total				**205,920**

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 10:

By J. Massie to G. Bentivegna
PDF p. 71, lines 15-24

> G. BENTIVEGNA: Thank you. And is -- does AEY have any policy regarding accepting sponsorships of a community event?
>
> J. MASSIE: I'll have to undertake to provide -- or not, if we have that policy. I can say that the majority of our sponsorship events have been long-standing events that we've had in place. So I'm just -- I'm not sure if we have a specific policy that dictates it as much as we just renew annual commitments to community events.

Response:

Please refer to Attachment 1 for AEY's Guidelines and Limitations on Sponsorships.

Community Investment Guidelines & Limitations

ATCO receives hundreds of requests for donations or sponsorship support throughout the year. To enable us to evaluate all opportunities, sponsorship or donation requests must be submitted online through our sponsorship portal.

Ineligible Organizations & Activities

The following organizations and/or activities are NOT eligible to receive funding:

Organizations

- Advocacy or lobbying organizations
- Churches or religious organizations
- Family Foundations, Trusts or Funds
- For-profit businesses
- Fraternal organizations or commercial third-party fundraising organizations

Activities

- Advertising or promotional initiatives not associated with a sponsorship and/or safety campaign
- Churches or religious organizations, unless offering broad, non-denominational community services.
- Conferences, seminars, workshops and conventions, unless relevant to the business of ATCO and its key areas of focus.
- Contingency or deficit funds
- General operating costs
- Health and welfare organizations already supported through our ATCO Employee
- Individual/team applicants and/or programs
- Participating in Communities (EPIC) program
- Political or partisan organizations or events
- Programs delivered outside ATCO's operating communities
- Research
- Retroactive funding for program expenses incurred prior to ATCO's funding decision
- Travel for individuals or groups
- Utility rebates

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 11:

By J. Massie to G. Bentivegna
PDF p. 77, lines 13-25 and PDF p. 78, lines 1-9

J. MASSIE: Yeah. We're not sure if it's in that specific example, assume it's distribution, as we don't have transmission assets. But on -- there's a distribution issue that causes issue, we're just not sure if it -- if it would be covered under the overall company insurance or not. But we do have insurance folks that we can check with for a specific example.

G. BENTIVEGNA: Yes. If you wouldn't mind, just to -- just to understand where -- what the assets that are insured and what liability is insured as opposed to, for example, general transmission lines that aren't and, you know, as you mentioned, buildings that belong to AEY that are.

J. MASSIE: So just to be clear, so it will be to find out what coverage we have for distribution line that may cause an external liability issue.

G. BENTIVEGNA: Yes. And maybe if you can add to that, like what your general liability insurance covers, in a sort of high level -- at a high level.

J. MASSIE: In a description of -- description of general liability?

G. BENTIVEGNA: Yes. Now, again, referring to the

Response:

AEY is covered under ATCO Ltd.'s general property liability policy with FM Global. The policy includes a $500,000 deductible and covers property damages at the locations outlined in Table 1 below. The insurance does not cover loss or damage to property owned by any person other than AEY.

Table 1: General Property Liability Locations

• Arkell Substation • Beaver Creek Power Plant • Carmacks Power Plant • Destruction Bay Power Plant • Fish Lake Power Plant #1 • Fish Lake Power Plant #2 • Haines Junction Power Plant • Old Crow Generating Plant	• Pelly Crossing Power Plant • Power Plant No. 1 Substation • Ross River • Stewart Crossing • Swift River Power Plant • Teslin Power Plant • Watson Lake Power Plant • Whitehorse Downtown Office • Whitehorse Service Centre

AEY does not have transmission and distribution line insurance and would utilize the Reserve for Injuries and Damages (RID) if an insurable event occurred that damaged or destroyed these assets. As outlined in the RID policy, the reserve serves as a protection against uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve will mitigate rate fluctuations by smoothing out the charges to

O&M with respect to these types of losses. The establishment of such a reserve provides financial advantages over paying significantly higher insurance premiums, in order to reduce deductibles or to insure items which carry prohibitively high premiums.

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 13:

By J. Massie to D. Ward
PDF p. 100, lines 3-21

D. WARD: But AEY itself does not have a written N-1-1 policy?

J. MASSIE: That would be what I would undertake to provide.

D. WARD: Thank you. Now, does the N-1-1 policy exist in other jurisdictions? Like, you could do it as an undertaking. Just give me a couple of jurisdictions where they apply that.

J. MASSIE: I certainly can look into the other jurisdictions. But, again, through that off-grid utilities association, that is part -- and there's, I want to say, a dozen utilities that are part of it. It's not just a couple that are in the north, Newfoundland and Lake Power I know are part of it, and any of the utilities in North America that operate these isolated grids are part of that association. And I know it's been discussed thoroughly in there, so I'm assuming other jurisdictions have the policies in place, but I can definitely check on that.

Response:

AEY's N-1-1 planning criteria is utilized only in the Watson Lake generation facilities where six generating units are required to supply community load. The criteria is based on the N-1 criteria; the ability to have the largest unit unavailable while supplying the system peak load. The N-1-1 criteria addresses the additional unplanned loss of the next largest unit.

Although AEY does not plan shutdowns during peak load periods, AEY has experienced situations where the two largest units were unavailable for an extended period and the remaining four generating units were required to operate to meet the peak load. With the unplanned loss of a third unit, standby generation was required to be on site.[1]

The N-1-1 planning criteria is not utilized in AEY's two and three engine power plants as the loss of the two largest units effectively results in an emergency condition. AEY mobile generating units are deployed in these situations. The Old Crow four-unit configuration will continue to be evaluated to the N-1-1 criteria as the power plant replacement project referenced in Business Case #41 proceeds.

As noted in Undertaking Response #14, the N-1-1 planning criteria was referenced in Business Cases #3 and #13 in the 2013 – 2015 AEY GRA even though the term N-1-1 was not specifically referenced.

AEY understands that Manitoba Hydro utilizes N-1-1 planning criteria; however, AEY is unable to reference their internal documents.

[1] Hearing Transcript Volume 3, PDF p. 101, lines 1-10.

ATCO ELECTRIC YUKON (AEY)

2023-2024 General Rate Application

ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 14:

By J. Massie to D. Ward
PDF p. 103, lines 18-25 and PDF p. 104, lines 1-14

D. WARD: Okay. Thank you. And last question on this topic. To meet that N-1-1 criteria, did you -- has AEY acquired any units specifically just for that criteria? And I'm not talking about on a short-term rental basis, just ...

J. MASSIE: I would have to take that away, Mr. Ward. Just the first thing that pops to mind is not really adding units as much as upsizing units, that I recall. It's just when a unit has come up for replacement due to end of life, the unit -- we'll look at the size of it and we can increase it from an 800 kilowatt to a 1,000 kilowatt, and some of that determination is for the N-1-1, not so much the load. But I'd have to take it away to understand if we replaced any units for it.

D. WARD: Okay. Thank you. And sorry, if you did replace any units just for N-1-1 purposes, can you let me know what the capital cost was at the time you acquired that unit?

J. MASSIE: Yes, I will undertake to provide -- and, again, the only ones I can think of is just upsizing existing units that are being replaced as opposed to replacing specifically for that.

Response:

AEY has not specifically acquired generation units to meet the N-1-1 criteria. As units are replaced in Watson Lake, the N-1-1 criteria is utilized in determining the size of the replacement unit.

In its 2013-15 GRA, AEY applied for, and the Board approved the replacement of generating units in the Watson Lake power plant, as described in Business Cases #3 and #13. While the term "N-1-1" was not specifically noted, the N-1-1 planning criteria was identified.

In the 2013-15 GRA Business Case 3 - Watson Lake Unit #4 Replacement, on page 3 of 4 in the technical drivers' section, AEY noted the following, which represents N-1-1 criteria:

Generation Capacity Required to Meet Electrical Load: This unit is rated at 1.5 MW and is the largest unit within the Watson Lake plant. Its unavailability due to its current state impacts the generating capacity of the plant.

Figure 1 – Watson Lake Generating Capacity

Watson Lake Generating Facility		
Unit #	**Unit Name**	**Unit Size (kW)**
1	CUL 422	800
2	CUL 257	800
3	CUL 352	1,000
4	CUL 258	1,500
5	CUL 466	650
6	CUL 423	800
Installed Capacity (kW)		**5,550**
Firm Capacity (kW)		**4,050**

In 2011, a peak of 3,205kW was recorded for the community; in 2012, a peak of 3,126kW was recorded. With CUL 258 unavailable, four out of the remaining available five units in the Watson Lake plant are required to supply reliable power. If the next largest unit, CUL 352, was also unavailable, the facility would then be unable to meet this peak.

Similarly, in the 2013-15 GRA Business Case 13 – Watson Lake Unit #2 Replacement, on page 3 of 4 in the technical drivers' section, AEY noted the following which represents N-1-1 criteria:

> Additional Generation Capacity Required to Meet Electrical Load: The Watson Lake plant had a recent peak of 3,205kW recorded for the community. With the addition of the new hospital and other forecasted residential loads, this peak is expected to rise. In the case of an unplanned loss of the largest unit in the Watson Lake plant (Unit #4), the remaining generators would not be able to be taken out of service for regular maintenance without negatively impacting customers. A major overhaul of a unit is usually 4-6 weeks in length; the minor overhauls are 1-2 weeks, during which time the unit is out of service.

Figure 1 – Watson Lake Generating Capacity

Watson Lake Generating Facility		
Unit #	**Unit Name**	**Unit Size (kW)**
1	CUL 422	800
2	CUL 257	800
3	CUL 352	1,000
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5	CUL 466	650
6	CUL 423	800
Installed Capacity (kW)		**5,550**
Firm Capacity (kW)		**4,050**

AEY has maintained this level of N-1-1 capacity for the Watson Lake power plant. AEY has not added generating units specifically for N-1-1 outside of these approved projects.

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ORAL HEARING

Date: November 29, 2023

Transcript: Volume 3

Undertaking 15:

By B. Rogers to G. Bentivegna
PDF p. 129, lines 16-25 and PDF p. 130, lines 1-17

M. JOHNSON: I have one request. So we've had some discussion about the capital expenditures, some projects this year that have been deferred, and earlier we do have an undertaking to provide an updated operating expense number for 2023. Could we get the same for incurred capital spend through 2023 to date? And I'm just looking for a bottom line number of the overall capital. Thank you.

J. MASSIE: Certainly.

CHAIR R. BUCHAN: Okay. I think that's all the questions

from the board. Mr. Myers?

T. MYERS: Before I commence with my re-examination, which is going to be very brief, I just wanted to clarify one thing about Mr. Johnson's question because we'd -- the witnesses have discussed it with Ms. Bentivegna in terms of providing the 2023 actual capital expenditures to date. And I don't think an undertaking was actually provided at that point, which is why I think Mr. Johnson was probably following up on it. But I just wanted to confirm, I think I heard Ms. Rogers indicate that that could be provided up until the end of -- I believe it was October. So I just wanted to make sure that the undertaking was clear in terms of up to what point those actual figures could be provided, just so we're clear on the undertaking.

CHAIR R. BUCHAN: Very good. Thanks for clarifying that.

B. ROGERS: Yes. October 31st if that's okay. Thank you.

Response:

AEY's total net capital expenditures for 2023 are outlined in Table 1 below.

Table 1: 2023 Capital Spend
($Millions)

	2023		
	October 31 YTD	**Full Year Forecast**	**Applied For**
Capital Expenditures	20.8	24.9	31.2
Contributions in Aid of Construction	(11.1)	(13.1)	(16.5)
Net Capital Expenditures	**9.7**	**11.8**	**14.7**

The full year Forecast is lower than applied for mainly due to delays in the Mayo Road substation project because of delays in receiving the required land use permit. The project is expected to be completed in 2024.

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Date: November 29, 2023

Transcript: Volume 3

Undertaking 16:

By B. Rogers to L. Tredger
PDF p. 174, lines 1-15

L. TREDGER: Thank you. And if the rate is -- if this rate application is approved as is, what would you expect those dividends to be over the next few years?

B. ROGERS: I don't have those exact figures in front of me. Again, it's a balance sheet exercise for us, so ensuring we've got the cash on hand that we need and that we're maintaining our equity ratios that are deemed to us through the regulatory process. So when we're looking at dividend payments, we're really looking -- we're looking relatively short term, so we adjust those dividend amounts as needed, as the actuals materialize.

L. TREDGER: Do you know what they are for 2023 yet?

B. ROGERS: Not off the top of my head, but I could undertake to provide.

Response:

Upon further review of its records, AEY has not declared or issued any dividends to its Shareholders in 2023.

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Date: November 30, 2023

Transcript: Volume 4

Undertaking 18:

By B. Rogers to G. Bentivegna
PDF p. 61, lines 4-8

> G. BENTIVEGNA: And so is AEY able to provide the board with the forecast percent allocations of net salvage costs for the five largest projects being added to rate base during either year of the current test period?
>
> B. ROGERS: I can undertake to provide that information.

Response:

The forecast percentage allocation of net salvage costs for the five largest projects being added to rate base in the Test Period is outlined in Table 1 below:

Table 1: Five Largest Removal Projects
($000)

Project	%	Test Period
New Services Overhead and Underground	4%	342
AEY New Substation Whistle Bend - Leota	9%	250
Mayo Road	9%	186
McIntyre Subdivision Rebuild	9%	112
AEY DWCI - New 12.5 kV substation	9%	71

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Date: November 30, 2023

Transcript: Volume 4

Undertaking 19:

By B. Rogers to G. Bentivegna
PDF p. 61, lines 9-19

G. BENTIVEGNA: Thank you. Now, is AEY able to provide the board with the percentage allocations of net salvage costs for five equivalent projects added to rate base during the period between 2018 to 2022?

B. ROGERS: To make sure I understand, you would like the five largest projects capitalized in the time period of 2018 to 2022 and the portion of those projects -- the percentage assumed to be net -- or salvage costs that were charged against the reserve?

G. BENTIVEGNA: Yes.

B. ROGERS: I can undertake to provide that as well, yes.

Response:

The percentage allocation of net salvage costs for the five largest projects that were added to rate base during the period from 2018-2022 is outlined in Table 1 below.

Table 1: Five Largest Removal Projects 2018-2022
($000)

Project	%	$
Watson Lake Unit 6 Replacement	10%	190
McIntyre Subdivision Rebuild	14%	157
Paint Mountain Conductor Replacement	21%	157
3 Phase Hotsprings Rd	25%	125
DWCI Dual Rated Transformers	18%	58

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Date: November 30, 2023

Transcript: Volume 4

Undertaking 20:

By B. Rogers to G. Bentivegna
PDF p. 65, lines 22-25 and PDF p. 66, lines 1-16

G. BENTIVEGNA: Sure. Well, it's really -- I mean, I'm focusing on the updates omissions and updates. But the IR was the second round IRs, B-6 at PDF page 10 regarding the account 390.01, structures and improvements - houses. And it was (n) of that number 2 IR. It's -- well, round 2, number 1, part (n) (iv) and (v).

B. ROGERS: I -- I do not have that information in front of me, but I can undertake to provide.

G. BENTIVEGNA: Now -- and that would be in relation to 390.01, the account 390.01, just to be clear.

B. ROGERS: Okay. Yes, I will undertake to provide. I don't have that information in front of me.

G. BENTIVEGNA: Okay. And also in that undertaking, if you could also explain where -- if the entries are related to specific capital projects and can those projects be identified and the percent of the project being allocated or charged to net salvage costs.

B. ROGERS: Yes, I can undertake to provide that information.

Response:

AEY notes it addressed the large debit balance in accumulated depreciation net salvage for Account 390.01 houses (Account 488.20 at that time) in its 2008-2009 GRA in reply to YEC-YECL-II-4(b)(i); please refer to Attachment 1. In summary:

> Since 1986 the net salvage rate applied to houses was –9.72% which was the rate applied to Alberta Power houses. Use of this rate resulted in a significant expense over time. Because there were no general rate applications since 1996 the rate remained in place.

AEY's proposed Net Salvage parameters in its 2013-2015 GRA included a provision to true up this balance over the asset's remaining life, which was denied as part of the denial to reinstate the collection of Net Negative Salvage in Board Order 2014-06. There have been no material transactions in this account since 2004. AEY cannot readily comment on any material transactions prior to 2004 since records for this account are stored offsite.

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YEC-YECL-II-4

Reference: YEC-YECL 17 (h)

(a) Please expand upon the response to YEC-YECL-17(h) to provide a detailed explanation and data in support of the different Estimated Net Salvage rates for the following items listed in Table 1 of the Gannett Fleming depreciation study included in the YECL GRA and Table 1A of the Gannett Fleming Depreciation Study conducted for Yukon Energy and included as Attachment 1 to YEC-YECL-II-2(b)(iii) to these interrogatories

(i) Distribution poles, towers and fixtures;

(ii) Overhead conductors and services;

(iii) Fuel holders, products and ACC;

(iv) Gen. equipment and prime movers.

(b) With reference to Table 2 at page 46 of the Gannett Fleming Study included in Section 7 of the YECL 2008/2009 GRA,

(i) Please provide a full explanation of the situation giving rise to the significant Variance in Accumulated Depreciation ($1.068) net salvage for company owned houses (Account 488.2).

(ii) Please provide the net salvage rate applied to this account prior to this Gannett Fleming depreciation study included as part of Section 7 to the YECL 2008/2009 GRA.

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Response:

(a) Yukon Electrical notes this question is requesting an expanded response to YEC-YECL-17(h), and requests explanation and support concerning the net salvage estimates developed by Gannett Fleming. However the original question YEC-YECL-17(h) was specific to asset lives and never requested any information with regard to net salvage. The original question was as follows:

> *"Please identify any asset lives used in the Depreciation Study that are less than the assets lives used (and approved by the YUB) for YEC for comparable assets (e.g. wood poles) in their last GRA, and provide an explanation and justification for each such shorter asset life adopted in the Depreciation study filed in YECL's Application."*

However in an effort to be as responsive as possible, Yukon Electrical is providing a response to this new un-related information request dealing with net salvage estimates.

The process used to determine the net salvage percentages for Yukon Electrical in this depreciation study was different than the process used in the depreciation study prepared by Gannett Fleming for Yukon Energy Corporation. At page II-6 of the Gannett Fleming Depreciation Study conducted for YEC (as included as attachment 1 to YEC-YECL-II-2(b)(iii)), the following is stated:

> *"Given the limited retirement experience, the estimates of net salvage were based primarily on judgment. The net salvage estimates were based on considerations of several factors including the net salvage characteristics of other electric utility properties, knowledge of management's plans and operating practices, and previous net salvage estimates used by the company."*

Given the limited retirement experience for YEC, Gannett Fleming developed net salvage estimates that would be considered as being at the low end of a range of reasonable net salvage rates. Selection of net salvage estimates at a low end of a range is appropriate in the circumstances that were facing YEC at that time. Until sufficient retirement data is collected, Gannett Fleming agrees that the net salvage percentages as developed for YEC are appropriate for YEC. However,

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retirement experience may in future years, indicate a requirement for larger net salvage percentages.

In contrast, the data sets provided to Gannett Fleming from Yukon Electrical included a significant level of retirement experience allowing for a much more detailed analysis of net salvage as described at pages II-26 and II-27 of the Gannett Fleming Yukon Electrical Depreciation Study. In the approach used for Yukon Electrical, the statistical analysis of the available retirement data becomes an important component of the net salvage estimate, which is then discussed with internal company experts, and compared to a peer group of companies, and prior estimates. As such, the process as used for the YEC study became only one step of the 6 step process used in the Yukon Electrical study.

The net salvage estimate for account 473.0 – Distribution Poles, Towers, and Fixtures was largely influenced by the 25 years of historic retirement experience. As indicated at Page V-11, the retirement experience over the past 25 years has indicated an actual cost of retirement of -83%, with net salvage percentages being in excess of -100% in 7 of the years. Also as indicated at page V-12 of the Depreciation Study report the most recent 5 year rolling band of historic retirement experience shows a cost of retirement of -98%, and the most recent 8 of the 3-year moving averages indicate net salvage requirements ranging from -77% to -159%. Based on this historic retirement experience, a net salvage estimate of between -80 to -100% would be appropriate. However, the previously approved estimate for this account was -50%. Therefore, it was determined that a moderated increase to -60% would be reasonable at this time, with further increases likely in future studies.

The net salvage estimate for account 474.0 – Distribution Overhead Conductor was also largely influenced by the 25 years of historic retirement experience. As indicated at Page V-13, the retirement experience over the past 25 years has indicated an actual cost of retirement of -115%, with net salvage percentages being in excess of -100% in 9 of the years. Also as indicated at page V-14 of the Depreciation Study report the most recent 5 year rolling band of historic retirement experience shows a cost of retirement of -176%, and the most recent 8 of the 3-year moving averages indicate net salvage requirements that all exceed -86%. Based on this historic retirement experience, a net salvage estimate of between -90 to -110% would be appropriate. However, the previously approved estimate for this account was -55%, and an increase of this

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magnitude would be too drastic to implement all at once. Therefore, it was determined that an increase to -70% would be reasonable at this time, with further increases likely required in future studies.

In both Account 444.0 – Fuel Holders, Products, and ACC, and Account 445.0 – Generating Equipment and Prime Movers, the amount of recent historic retirement experience was not as extensive as in the other accounts. However the experience did indicate some trends that were meaningful. Specifically, even the limited retirements in both accounts do indicate a trend to negative net salvage requirements. Additionally Gannett Fleming noted that the recent years which had larger levels of retirements generally provided larger levels of costs of retirements. This trend is consistent with the increasing level of environmental requirements that these types of assets are subjected to when removed. As such, it was considered appropriate to raise the net salvage percentages from the -5% previously approved in both accounts to -30% and -10% for accounts 444.0 and 445.0 respectfully.

(b) (i) Since 1986, the net salvage rate applied to houses was -9.72% which was the rate applied to Alberta Power houses. Use of this rate resulted in significant expense over time. Because there were no general rate applications since 1996 the rate remained in place. Mr. Kennedy's depreciation study included an examination of the appropriate life and net salvage parameters to use for houses. The Calculated Accumulated Depreciation Net Salvage resulting from the recommended net salvage percentage results in significantly lower accumulated depreciation compared to the book accumulated depreciation net salvage.

(ii) The net salvage rate was -9.72%.

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Date: November 30, 2023

Transcript: Volume 4

Undertaking 21:

By B. Rogers to G. Bentivegna
PDF p. 70, lines 1-25, PDF p. 71, lines 1-25, PDF p. 72, lines 1-25, and PDF p. 73, lines 1-3.

G. BENTIVEGNA: Okay. So we've got account 367.00, 368.00, and 373.00. And if you need to provide the information by undertaking, it would be similar to the other account, as well as then explaining if it -- the entry is related to specific capital projects, and if the capital projects could be identified in the percentage of the project being allocated to net salvage costs.

L. KENNEDY: I'm going to try a theoretical answer for you and see if that helps.

G. BENTIVEGNA: All right.

L. KENNEDY: It's very possible these accounts are in a negative position. When we have had a number of years since we've funded the reserve, but yet we are continuing to charge the reserve for the costs of removal that are going forward. So these negative

numbers that we see on the table that you took us to, I haven't got the detail in front of me, but it's highly likely that those are accounts that as this account has not been funded for many years, it's ran itself into a negative position.

In other words, we've charged more against the reserve that's in there. And so that would result in these reserves appearing negative. And we see that -- we see that with organizations. It's one of the problems of not funding the reserve and letting the reserve draw down, because we're looking at it on a total basis. There is in total a net reserve available. But account by account, some have funds available and some are overdrawn. And these accounts I believe are ones that are -- just in fact have been overdrawn by the fact we haven't funded anything into the reserve specific to those accounts.

G. BENTIVEGNA: Thank you for that explanation, Mr. Kennedy. But we'd still like to understand what's causing the end of the specific projects, what's causing these amounts, the same as in the previous account we discussed.

B. ROGERS: I maybe want to -- for this and the previous undertaking, as we've discontinued the collection of net negative salvage a number of years ago, a 2009

decision I believe, there's quite potentially a significant amount of information for us to go through to see all of this information. Is there a time period that you would like us to look at, as far as transactions in this account? Because there is potential that this was sitting in a balance similar to this, even at the time in which the discontinuation of net negative salvage was instated.

G. BENTIVEGNA: Certainly. So then if you can undertake to provide it once you've gone through to provide information.

B. ROGERS: I'm not sure I can pull information as far back as what makes up this balance. This is a long-standing reserve account, and collections and funding within the account were on a cumulative full balance basis in 2009, subject to check. And at that point in time, I -- I anticipate there was an amortization of differences proposed that was ultimately not approved. So to the extent that there's balances potentially going back into the early 2000s, '90s, I'm not sure that we can provide that information on a timely basis for this proceeding.

G. BENTIVEGNA: Right. What about since 2009? Would you be able to provide the information since that time period? Well, since that year?

B. ROGERS: We should be able to provide the transactions for those accounts back to 2009, yes.

G. BENTIVEGNA: Thank you.

Response:

From January 1, 2010 to December 31, 2022, AEY has incurred removal costs in the amount of $1,534,414 for Accounts:

- 367.00 - Underground Conductors and Devices
- 368.00 - Line Transformers
- 373.00 - Streetlights

As net salvage collection was discontinued in Board Order 2009-2, these removal costs have drawn down the reserve which, for accounts 367.00 and 373.00, were already in negative positions, resulting in the negative positions as shown below:

Table 1: Net Salvage Book Accumulated Depreciation

Account	Salvage Book Accum. December 31, 2009	Removal Costs 2010-2022	Salvage Book Accum. December 31, 2022
367.00 – Underground Conductors and Devices	(66,484)	(392,956)	(459,441)
368.00 – Line Transformers	330,705	(803,729)	(473,024)
373.00 - Streetlights	(236,138)	(337,728)	(573,867)
Total	**28,083**	**(1,534,414)**	**(1,506,331)**

Please refer to Attachment 1 for large removal projects/programs and their associated removal percentages.

ATCO Electric Yukon (AEY)
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Undertaking Response 21 - Large Removal Costs Projects/Programs since 2009 for Accounts 367.00, 368.00 and 373.00

Account 36700 - Underground Conductors and Devices

Line No	Name	Amount	Removal %
1	**Name**	**Amount**	**Removal %**
2	Paint Mountain Conductor Replacement	156,696	21%
3	McIntyre Village Multi-Phase Redevelopment	40,600	6%
4	Distribution Improvement and New Extension Projects	98,243	Note 1
5	**Total**	**295,539**	

Account 36800 - Line Transformers

10	**Name**	**Amount**	**Removal %**
11	Transformer Disposal	393,030	Note 2
12	Transformer Upgrades and Change outs	342,901	Note 3
13	DWCI Dual Rated Transformers	57,528	18%
14	**Total**	**793,458**	

Account 37300 Street lights

18	**Name**	**Amount**	**Removal %**
19	Customer Driven Streetlight Projects	128,518	Note 4
20	System Street Lights	106,812	Note 5
21	McIntyre subdivision street light replacement	49,114	9%
22	**Total**	**284,445**	

Note 1: This program consists of multple projects with removal percentages ranging from 7% to 38%. Each project % is determined on an individual basis

Note 2: These costs are for the disposal of oil filled equipment such as transformers. The costs involve testing for polychlorinated biphenyls, removal of contanimated parts, shipping, and final disposal costs. Please note, that these costs are accounted for at 100% removal rate but these line transformers were in service and replaced by new transformers on various projects.

Note 3: This program consists of multple transformer replacements. These costs include multiple transformers and can range from 5-18% removal percentage.

Note 4: This program consists of multiple projects with removal percentages ranging from 1% to 28%. Each project is determined on an individual basis.

Note 5: This program consists of multiple projects with removal percentages ranging from 9% to 25%. Each project is determined on an individual basis.