



Alberta Electric System Operator

2014 ISO Tariff Application and 2013 ISO Tariff Update

August 21, 2014

The Alberta Utilities Commission

Decision 2014-242: Alberta Electric System Operator
2014 ISO Tariff Application and 2013 ISO Tariff Update
Application No. 1609765
Proceeding No. 2718

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1 Introduction

1. On July 17, 2013, the Alberta Electric System Operator (AESO) filed for approval its 2014 ISO (Independent System Operator) Tariff (the application or general tariff application (GTA)) and its 2013 ISO Tariff Update (2013 tariff update) with the Alberta Utilities Commission (AUC or the Commission). On July 19, 2013, the AESO filed a revised application including revised rate calculations and bill impacts.¹

2. In the 2013 tariff update, the AESO requested:

- (a) approval of the updated dollar amounts calculated for the AESO's 2013 rates in Appendix C and presented in Appendix D of the application;
- (b) approval of the updated investment levels calculated for the AESO's 2013 contribution policy in Section 4.4 of the application;
- (c) approval of export opportunity merchant service Rate XOM, applicable to exports over the Alberta-Montana intertie when it entered service during 2013; and
- (d) approval of the rate and rider schedules and terms and conditions set out in Section 8, which reflected the updates in Appendix D of the application.

3. The Commission approved the 2013 tariff update on an interim refundable basis in Decision [2013-325](#),² issued on August 28, 2013. In that decision, the Commission ordered that the 2013 tariff update be tested concurrently with the application.³

4. In the application, the AESO requested:

- (a) approval of the bulk system, regional system, and point of delivery cost functionalization, and the bulk system and regional system cost classification, for 2014, 2015, and 2016 as presented in Table 5-2 in Section 5 of the application;
- (b) approval of the proposed 2014 tariff set out in Appendix L of the application, including rates, riders, terms and conditions, and tariff appendices;
- (c) confirmation from the Commission that the AESO's entire forecast revenue requirement is subject to deferral account treatment;

¹ Exhibit nos. 24-26.

² Decision 2013-325: Alberta Electric System Operator, 2013 ISO Tariff Update, Application No. 1609765, Proceeding No. 2718, August 28, 2013.

³ Decision 2013-325, paragraph 18.

- (d) confirmation from the Commission that the AESO shall continue to employ Rider C and an annual deferral account reconciliation process to ensure the recovery of all actual incurred costs except those related to losses, until such time as the Commission approves changes to that process;
- (e) confirmation from the Commission of its acceptance of the AESO's responses to outstanding directions; and
- (f) such other relief as the Commission deems appropriate.

5. Notice of the application (notice) was issued by the Commission on July 19, 2013. In accordance with the deadline set out in the notice, statements of intent to participate (SIPs) were received on or before August 2, 2012 from the following parties:

- the Alberta Direct Connect Consumers Association (ADC)
- Access Pipeline Inc. (Access)
- AltaLink Management Ltd. (AltaLink or AML)
- ATCO Power Ltd. (ATCO Power)
- BC Hydro
- Capital Power Corporation (Capital Power)
- City of Red Deer
- City of Lethbridge
- Consumers' Coalition of Alberta (CCA)
- Devon Energy Corporation (Devon)
- Dual Use Customers (DUC)
- Enbridge Montana Alberta Tie Ltd. (MATL)
- Enbridge Pipelines (Athabasca) Inc. (Enbridge)
- EnerNOC, Inc. (EnerNOC)
- ENMAX Corporation (ENMAX)
- EPCOR Distribution & Transmission Inc. (EDTI)
- FortisAlberta Inc. (FAI or FortisAlberta)
- the Industrial Power Consumers Association of Alberta (IPCAA)
- Powerex Corp. (Powerex)
- the Office of the Utilities Consumer Advocate (UCA)
- TransAlta Corporation (TransAlta)
- TransCanada Energy Ltd. (TCE)
- TransCanada Keystone Pipeline GP Ltd. (Keystone)

6. On July 24, 2013, the AESO issued an invitation to interested parties to attend a general technical meeting to discuss the proposals set out in the application other than the cost causation study prepared by London Economics Inc. (LEI) and a second technical meeting to discuss the cost causation study prepared by LEI. These meetings were held on August 8, 2013 and August 19, 2013, respectively.

7. On August 28, 2013, the AESO filed its construction commitment agreement *proforma* as an addendum to the application.⁴ The AESO had indicated at the time it filed the application that the construction commitment agreement would be filed at a later date. Also on August 28, 2013, the AESO filed answers to questions asked by parties during the course of the two technical meetings.

8. On August 29, 2013, the AESO requested approval from the Commission to initiate negotiated settlement discussions with parties with a view to reaching a settlement on the 2014-2016 Cost Causation Study prepared by LEI. The point of delivery (POD) cost function, rate design matters and terms and conditions were not included as part of the negotiated settlement process. On September 10, 2013, the Commission issued Decision 2013-340⁵ approving the AESO's request to negotiate matters related to the 2014-2016 Cost Causation Study.

9. On November 7, 2013, the AESO filed its negotiated settlement agreement with the Commission for approval. The AESO submitted that the settlement had been unanimously supported and that no issues with respect to the 2014-2016 Cost Causation Study remained unresolved. On November 27, 2013, the Commission issued Decision 2013-421⁶ approving the negotiated settlement agreement.

10. On November 17, 2013, the AESO filed correspondence with the Commission requesting that the schedule for the application be amended to accommodate the development of a revised *proforma* construction commitment agreement. On November 25, 2013, because of the limited time available before the oral hearing for parties to review and respond to revisions on the *proforma* construction commitment agreement and any related revised tariff provisions, the Commission directed the AESO to identify and remove the *proforma* construction commitment agreement and any related documents or parts of documents from the record of this proceeding. On December 11, 2013, the AESO submitted correspondence advising that the following documents had been removed:

- (a) the *proforma* Construction Commission Agreement included as part of Appendix B of the proposed 2014 ISO tariff;
- (b) subsection 3 of Section 5 of the terms and conditions of the proposed 2014 ISO tariff, relating to Form and Provision of Financial Security for Projects Eligible for Local Investment (parts 3(1) through 3(6) inclusive); and
- (c) subsection 5 of Section 5 of the terms and conditions of the proposed 2014 ISO tariff, relating to Cancellation (parts 5(1) through 5(7) inclusive).

⁴ Exhibit No. 71.02.

⁵ Decision 2013-340: Alberta Electric System Operator, AESO 2014 ISO Tariff Application and 2013 ISO Tariff Update, Request to Enter into a Negotiated Settlement Process, Application No. 1609765, Proceeding No. 2718, September 10, 2013.

⁶ Decision 2013-421: Alberta Electric System Operator, AESO 2014 ISO Tariff Application and 2013 ISO Tariff Update, Negotiated Settlement – Cost Causation Study, Application No. 1609765, Proceeding No. 2718, November 27, 2013.

11. Intervener evidence was filed on or before December 5, 2013, by the following parties:

- ADC, evidence prepared by Collette Chekerda (the Chekerda evidence) and Michael Gorman (the Gorman evidence)
- ATCO Power (the ATCO evidence)
- the CCA (the CCA evidence)
- Devon Canada Corporation and Access Pipeline Inc., evidence prepared by Depal Consulting (the Depal evidence)
- FortisAlberta (the FortisAlberta evidence)
- IPCAA, evidence prepared by Drazen Inc. (the IPCAA evidence)
- DUC, evidence prepared by Desiderata Consulting (the DUC evidence)
- UCA, evidence prepared by Robert Spragins (the Spragins evidence) and Power Advisory (the UCA evidence)
- EnerNOC (the EnerNOC evidence)
- TCE (the TCE evidence)

12. On December 23, 2013, the AESO issued correspondence to the Commission in which it submitted that TCE had filed intervener evidence proposing a new supply opportunity service (SOS) rate, the effect of which would be to require new entrants to curtail generation so that incumbent generators can use existing transmission capacity in times of transmission constraints. The AESO stated that this issue was of significant concern to the industry and suggested that fully addressing the system access issue and TCE's proposed SOS rate in the context of the application had the potential to extend significantly the oral hearing beyond the 10 days the Commission had scheduled. The AESO requested that the Commission either deal with TCE's proposed SOS rate in a separate module of the proceeding or establish a separate process to consider the issue. On December 30, 2013, the Commission issued a letter in which it requested comments from the parties on the AESO's submission.

13. On January 10, 2014, the Commission directed TCE's Rate SOS proposal be heard in a separate module of Proceeding No. 2718 (Rate SOS module or Module 2). The record of Proceeding No. 2718 relating to the Rate SOS proposal, including any information responses provided by TCE regarding its Rate SOS proposal evidence, was transferred to Module 2. On January 31, 2014, the Commission issued a process and schedule for the Rate SOS module. The schedule allowed for a written process for Module 2. Module 2 is discussed in greater detail in a separate section of this decision.

14. On January 20, 2014, the AESO submitted rebuttal evidence covering those matters to be considered in the oral hearing. The AESO's rebuttal evidence did not include any comment on the Rate SOS module.

15. On January 21, 2014 the AESO filed a revised 2014-2016 Cost Causation Study and related materials pursuant to the Commission's directions in Decision 2013-421 which approved the negotiated settlement agreement.

16. An oral hearing to consider all matters in the application with the exception of the Rate SOS module was held at the Commission offices in Calgary from January 27, 2014 to

February 4, 2014. Written argument with respect to the main hearing was received from the parties on March 19, 2014 and written reply argument was received on April 11, 2014.

17. The AESO submitted rebuttal evidence with respect to the Rate SOS module on April 4, 2014. Written argument on Module 2 was received from parties on April 14, 2014 and written reply argument was received on April 25, 2014.

18. On May 2, 2014, the Commission received correspondence from ENMAX in which ENMAX expressed concern with certain comments made in the reply arguments of the AESO, BluEarth and Capital Power. ENMAX requested leave to file sur-reply in response to these comments. On May 2, 2014, the Commission received comments from the AESO in response to ENMAX's letter. On May 5, 2014, the Commission found the references in the AESO's reply argument to be positional in nature and therefore considered that they did not put evidentiary matters at issue nor necessitated the filing of a sur-reply. Therefore, the Commission denied ENMAX's request for leave to file sur-reply.

19. On May 15, 2014, the Commission received a letter from ATCO Power regarding transmission line loss charges and what effect, if any, Commission Decision [2014-110](#)⁷ had on the transmission line loss charges proposed in the application. The Commission requested parties to submit brief supplemental argument submissions on this matter by June 6, 2014.

20. The Commission considers that the record for Proceeding No. 2718 closed on June 6, 2014.

21. 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. This decision reflects the Commission's findings from all of the evidence on the record of this proceeding, including those issues that were addressed in the Rate SOS module of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 2013 ISO tariff update

22. The 2013 tariff update was approved by the Commission on August 28, 2013, on an interim refundable basis, in Decision 2013-325. In that decision, the Commission ordered that the 2013 tariff update be tested concurrently with the application.⁸ The following section outlines the Commission's consideration of the 2013 tariff update and the findings with respect to it.

⁷ Decision 2014-110: Alberta Electric System Operator, Capital Power Corporation, TransAlta Corporation and TransCanada Energy Ltd., Applications for review of AUC Decision 2012-104: Complaint by Milner Power Inc. regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, Application Nos. 1609554, 1609555, 1609556 and 1609557, Proceeding No. 2581, April 16, 2014.

⁸ Decision 2013-325, paragraph 18.

2.1 Updated dollar amounts for 2013

23. The AESO stated that it continued to use the tariff update approach approved by the Commission in Decision 2010-606⁹ and that the AESO had filed updated rate and investment levels in the 2013 tariff update in accordance with this approved approach. For the 2013 tariff update, the AESO submitted that it utilized the same functionalization, classification, and allocation of the AESO's revenue requirement as directed in Decision 2010-606 and that it maintained the same design and structure of the AESO's rates as directed in that decision. The AESO submitted that with respect to the 2013 annual revenue requirement, no party has raised concerns with any costs, with the exception of 2013 load shed service for imports (LSSi) costs.¹⁰

24. The AESO agreed that LSSi costs are relevant to both 2013 and 2014 and submitted that any Commission determinations with respect to LSSi should apply to both 2013 and 2014. The AESO submitted that should the Commission direct any changes to the proposed treatment of LSSi costs in 2013, those changes should be addressed at the time of the AESO's 2013 deferral account reconciliation application or a subsequent deferral account reconciliation, rather than through a retroactive adjustment of the AESO's 2013 tariff and rebilling of market participants.¹¹ No party objected to this proposed methodology.

25. The AESO submitted that no party had raised any concerns with respect to the revised rate levels in Appendix C¹² of the application and incorporated in the rate and rider sheets in Appendix D¹³ of the application.

26. Access and Devon submitted evidence proposing that point of delivery charges should be based on updated project costs, including five years of recent project costs, and be effective on October 1, 2013.¹⁴ Access and Devon referenced the finding of the Commission, in its letter, dated March 11, 2013, at paragraph 6 in which it stated, in part:¹⁵

The Commission panel assigned to Decision 2012-362¹⁶ made no findings about the investment level and directed a consideration of this issue as part of the Alberta Electric System Operator's (AESO) next comprehensive tariff application.

27. Therefore, Access and Devon brought this issue before the Commission in this proceeding.

28. Access and Devon also objected to the AESO's proposed revised effective date for its 2014 contribution policy. The AESO proposed that rates and investment levels should now be implemented on October 1, 2014 due to delays in this proceeding and because the AESO

⁹ Decision 2010-606: Alberta Electric System Operator, 2012 ISO Tariff, Application No. 1605961, Proceeding No. 530, December 22, 2010, paragraph 537.

¹⁰ Exhibit No. 366.01, AESO argument, paragraph 32.

¹¹ Exhibit No. 366.01, AESO argument, paragraph 33.

¹² Exhibit No. 5.

¹³ Exhibit No. 6.

¹⁴ Exhibit No. 146.02, the Depal evidence.

¹⁵ Exhibit No. 112.06, paragraph 6.

¹⁶ Decision 2012-362: Alberta Electric System Operator, 2012 Construction Contribution Policy, Application No. 1067193, Proceeding ID No. 1162, Application to review Decision 2012-362, Decision Letter dated March 11, 2013.

required at least 60 days to implement new rates.¹⁷ Access and Devon disagreed with the AESO and submitted that delays in Proceeding No. 2718 should not effect changes in investment levels. It would be unfair and unreasonable for procedural delays to have a multi-million dollar effect on individual project costs and therefore, at minimum, the Commission should consider the delays in this proceeding when determining the implementation date for investment levels.¹⁸

Commission findings

29. The Commission has reviewed the AESO's 2013 tariff update and finds that the AESO has reasonably applied the tariff update approach as approved by the Commission in Decision 2010-606 to file its 2013 tariff update. In arriving at this determination, the Commission finds that the AESO has applied the functionalization, classification, and allocation of its revenue requirement as directed in Decision 2010-606.

30. No parties objected to the revised rate levels in Appendix C of the application and the revised rate and riders in Appendix D of the application. With respect to LSSi costs, the Commission accepts the AESO's proposal that any changes to the proposed treatment of LSSi costs should be addressed in an AESO deferral account reconciliation application rather than through a retroactive adjustment to the AESO's 2013 tariff. Further, in Section 8.1 of this decision, the Commission discusses its determinations with respect to 2013 transmission line loss costs. For these reasons, the Commission approves the 2013 ISO Tariff Update on a final basis subject to any findings made later in this decision with respect to LSSi costs and transmission line loss costs.

31. With respect to Access and Devon's concerns about the maximum investment levels calculated for the 2013 tariff update and the effective date for implementation of the 2014 contribution policy, the Commission's determinations on these issues are discussed in Section 6.3 of this decision.

3 Forecast costs and approval process

3.1 Legislative scheme

32. Section 119(4) of the *Electric Utilities Act*, SA 2003, c. E-5.1, requires the AESO to prepare a tariff and to apply to the Commission for approval of this tariff. The tariff is composed of two elements: (1) costs and expenses and (2) the proposed allocation of costs and expenses to rate classes (rate design).

33. Generally, there are four principle categories of costs and expenses incurred by the AESO that are included in its tariff: (1) the AESO's own administrative costs; (2) ancillary services costs; (3) transmission line losses; and (4) costs related to transmission wires (payable under a TFO tariff). The provisions of the *Electric Utilities Act*, and the *Transmission Regulation*, AR 86/2007, provide specific direction to the Commission regarding the extent to which the Commission may assess these costs and expenses.

¹⁷ Exhibit No. 366.01, AESO argument, paragraph 227.

¹⁸ Exhibit No. 396.01, Access/Devon reply argument, paragraphs 24-27.

34. The AESO's own administrative costs are defined in Section 1(1)(g) of the *Transmission Regulation* to include: (1) the transmission-related costs and expenses of the AESO respecting the administration, operation and management of the AESO; (2) the transmission-related costs and expenses of the AESO respecting reliability standards and reliability management systems; and (3) the transmission-related costs and expenses required to be paid by the AESO except for the costs of providing ancillary services, costs of transmission line losses and amounts payable under TFO tariffs.

35. The AESO's own administrative costs are approved by the AESO's board, defined in the *Transmission Regulation* in Section 1(f) as "ISO members." Section 3(1) of the *Transmission Regulation* requires the AESO to engage in consultation with those market participants who are likely to be directly affected by the approval by the AESO board of its own administrative costs. Consequently, Section 46 (1) of the *Transmission Regulation* limits the Commission's review of the AESO's own administrative costs to those costs which an interested party has argued are unreasonable. Moreover, the onus is on the interested party, not the AESO, to satisfy the Commission that the AESO's own administrative costs are not reasonable. Absent this, the provisions of the *Transmission Regulation* require the Commission to consider the AESO's own administrative costs to be prudent.

36. Similarly, the AESO board also approves the costs for ancillary services and line losses. Consequently, Section 3 (1) of the *Transmission Regulation* also requires the AESO to consult with market participants directly affected by these costs. However, there is no equivalent provision to Section 46 (1) of the *Transmission Regulation* that provides an interested party with the ability to argue the reasonableness of these costs before the Commission. Instead, Section 20 of the *Electric Utilities Act* and sections 15, 17, 33 and 34 of the *Transmission Regulation* authorize and, in some instances, direct the AESO to establish rules related to the calculation and recovery of ancillary service costs and costs for line losses.¹⁹ Consequently, where ISO rules are proposed or created for the calculation and recovery of ancillary service costs or the costs for line losses, the Commission's oversight of these costs is addressed through the objection and complaint provisions found in sections 20 and 25 of the *Electric Utilities Act*, respectively.

37. The Commission tests the amounts payable under the TFO tariffs in separate transmission tariff proceedings for each of the transmission utilities that provide transmission services to the AESO. Therefore, these costs are not tested in the AESO tariff.

38. With respect to the tariff design, the legislation provides further direction to the Commission in Section 30 of the *Electric Utilities Act* and Section 48 of the *Transmission Regulation*.

39. It is against this legislative backdrop that the Commission has provided its assessment of the AESO's tariff application in this proceeding.

3.2 Revenue requirement

40. In Section 2 of the application, the AESO explained that its revenue requirement is composed of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration costs, which include other industry costs in its 2013 forecast or 2014

¹⁹ Section 30(4)(b) of the *Electric Utilities Act* also permits the recovery of these costs by AESO fee.

projected revenue requirements. As explained above, the AESO's forecast costs are approved through other processes and are not approved as part of this proceeding. The AESO noted that it has the responsibility to collect the costs of ancillary services and line losses under Section 30(4) of the *Electric Utilities Act* while the AESO's own costs are to be collected in accordance with Section 1(1)(g) of the *Transmission Regulation*.

41. The AESO's forecast revenue requirements for 2013 and 2014 were summarized in Table 2-1 of the application and a detailed breakdown of the individual components was provided in Table 2-2.

42. The AESO's forecast costs and processes for their approval are as follows:

- (a) Wires-related costs reflect the amounts paid by the AESO to transmission facility owners in their tariffs approved by the Commission under Section 37 of the *Electric Utilities Act*. (The wires costs forecast included in the AESO 2013 Business Plan and Budget Proposal reflect TFO tariffs applied-for or approved by the Commission at the time the AESO budget was prepared in late 2012.)
- (b) Ancillary services costs reflect recovery of the prudent costs incurred by the AESO related to the provision of ancillary services acquired from market participants under Section 30(4) of the *Electric Utilities Act*.
- (c) Line loss costs reflect recovery of the prudent costs of transmission line losses under Section 30(4) of the *Electric Utilities Act*.
- (d) Administrative costs reflect the transmission-related costs and expenses incurred by the AESO in accordance with Section 1(1)(g) of the *Transmission Regulation*.

43. The AESO explained that it determined wires costs for transmission facility owners using the approach described in Section 2.2 of the AESO's 2010 ISO Tariff application (pages 14-15, paragraphs 48-56) and approved in Decision 2010-606. Specifically, the AESO has included costs that reflect the status of each transmission facility owner's application for the effective tariff year of the AESO's revenue requirement.

44. In Section 2.3 of the application, the AESO explained that ancillary services, as defined in the *Electric Utilities Act*, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserves. Operating reserves represent unloaded generating capacity that is available to respond to temporary shortfalls in supply caused by loss of a generating unit, loss of intertie capacity, or fluctuations in load. Ancillary services costs are a function of volume forecasts and market-based commodity pricing forecasts.

45. In Section 2.4 of the application, the AESO explained that line losses reflect the energy lost on the transmission system when power is transmitted from suppliers to loads. These losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads. Like ancillary service costs, line loss costs are a function of volume forecasts and market-based commodity pricing forecasts.

46. As noted by the AESO in Section 2.5 of the application, administrative costs are defined in Section 1(1)(g) of the *Transmission Regulation*. The AESO board approves the AESO's administration costs in their entirety. However, the amounts recovered through the AESO's tariff

include only the transmission-related portions of those costs. Further, the AESO board approval includes the allocation of administrative costs among the three functions of the AESO, namely, transmission, energy market, and load settlement.

47. The AESO's revenue requirement forecasts for 2013 and 2014 reflecting the updated 2014-2016 cost causation study were updated²⁰ and filed prior to the start of the oral hearing in accordance with the negotiated settlement agreement.

3.3 Consultation

48. In Section 3 of the application, the AESO explained that, in addition to stakeholder involvement in the AESO's Budget Review Process discussed in Section 2.1 of the application, stakeholders were also consulted during the development of its 2014 tariff proposals. The stakeholder consultation was conducted from November 2012 through June 2013 and included three initiatives:

- a small working group established to examine transmission cost causation in depth, including reviewing drafts of the transmission cost causation study prepared by London Economics for this application
- two general stakeholder meetings to provide information on the development of the tariff application proposals and receive feedback and comments on those proposals
- focussed stakeholder meetings on specific topics, including construction contribution policy and recovery of costs of load shed service for imports

49. The cost causation working group included nine stakeholder representatives and met on eight occasions to discuss issues and exchange information related to cost causation and rate design. Information related to the activities of the working group was posted on the AESO website.

50. The AESO also considered information from other ongoing consultations in the development of its tariff, including:

- connection process refinements
- interties policy
- the transition of authoritative documents (TOAD) project

51. The AESO asserted that the various consultation initiatives and processes provided stakeholders with multiple opportunities to provide input into the development of the AESO's tariff application. Although transmission cost causation working group membership was limited to improve the effectiveness of the process, materials from the working group were usually posted on the AESO's website and other stakeholders were invited to review those materials and provide comments to the AESO or working group members. No stakeholders were excluded from participating in the general stakeholder meetings, and all stakeholders had the opportunity to contact the AESO at any time and discuss the tariff application. The AESO also met individually with stakeholder groups or representatives who requested the opportunity to discuss informally the tariff application.

²⁰ Exhibit No. 265.

52. The AESO explained that the purpose of the tariff consultation was not necessarily to achieve consensus among interested parties but to provide opportunities for the AESO and stakeholders jointly to examine the reasonableness of tariff proposals and to consider the interests of all parties in such an examination. The AESO stated that it considered the input and advice stakeholders provided during consultation although the AESO acknowledged that not every aspect of this application was raised with stakeholders. Some proposed changes, including some revisions to the terms and conditions, arose late in the application's development with little opportunity for consultation.

53. The AESO noted that, pursuant to sections 121(2) and 122(3) of the *Electric Utilities Act*, when considering an ISO tariff application, the Commission may not decide that the tariff fails to satisfy the requirements that it be just and reasonable and that it not be unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any law, simply because the tariff provides for the flow-through of the AESO's "prudent costs and expenses of carrying out its duties, responsibilities and functions."²¹ As further explained in Section 48(1) of the *Transmission Regulation*, a reference in the act to "prudent" or "appropriate" in relation to the ISO's costs for the provision of (i) ancillary services and (ii) costs of transmission line losses means "the amounts of those costs that have been approved by the ISO members."²² Section 46(1)(b) of the *Transmission Regulation* provided that the Commission must consider the ISO's own administrative costs that have been approved by the ISO members as prudent unless an interested person satisfies the Commission that those costs or expenses were unreasonable.

54. In argument, the CCA expressed concern that there did not appear to be active participation from a broad cross-section of stakeholder groups. For example, with respect to the 2013 budget review process, while there were certain other parties involved in the budget review process, the AESO board only received written submissions from three stakeholders, all of whom represented large industrial customers. The CCA questioned whether such views are necessarily representative of all load customers, in all cases.

55. Another issue of concern to the CCA was whether the AESO board, in the testing of the AESO's own administrative costs, undertook an assessment of these costs by means of benchmarking studies or otherwise retained independent external experts to review the forecast costs under the AESO board's review. If such independent experts were retained, the nature and extent of reliance on these experts or on benchmarking studies is not evident. The CCA noted that the costs under review amount to approximately \$474.9 million (ancillary services, line losses and administration), which represents 25 per cent of the total approved AESO 2014 revenue requirement of \$1,873.7 million.

56. As the costs under review are not insignificant and as the Commission must consider these forecast costs to be prudent, the CCA submitted that having independent external experts review and assess the costs forecast by AESO management and which are subject to approval by the AESO board, may be "money well spent."²³ For example, these experts could examine the reasonableness of forecast costs by developing metrics that provide a measure of whether the AESO is utilizing its internal resources in an effective and efficient manner. These experts may

²¹ Exhibit No. 366.01, AESO argument, paragraph 54, page 16.

²² *Transmission Regulation*, Section 48(1).

²³ Exhibit 371.02, CCA argument, page 11.

also review whether the changes in labour costs forecast by the AESO, for example, are supportable by reference to changes in labour costs experienced by other utilities in Alberta which compete for essentially the same pool of labour.

57. In the CCA's view, the retention of independent experts would provide all stakeholders with the assurance that the AESO board has information before it, from sources other than management itself, that either supports or refutes the quantum of costs forecast by AESO management.

58. The CCA further noted that the *Transmission Regulation* clearly states that the Commission must consider that "the ISO's own administrative costs that have been approved by the ISO members are prudent unless an interested person satisfies the Commission that those costs or expenses are unreasonable."²⁴ The CCA noted the AESO board did not come to the conclusion in its decision on the AESO's business plan and budget proposal that costs were prudent; rather it concluded these costs were "reasonable." Further, the CCA argued that it did so in spite of the fact that the AESO acknowledged that the words "reasonable" and "prudent" are not interchangeable.

59. Given the above, the CCA was uncertain as to why the AESO board decision did not explicitly state that the forecast costs under review were prudent instead of stating the costs it has reviewed are "reasonable." Given the obligation imposed in the *Transmission Regulation*, if the Commission is to deem these costs as prudent, the CCA maintained the AESO board decision must first come to that conclusion. The CCA recommended the Commission direct the AESO to provide an explanation, in its compliance filing, why the AESO board decision uses the word "reasonable" as opposed to the word "prudent" in approving the forecast costs under its review.

60. In reply argument, the AESO refuted the CCA's suggestion that the budget review process was flawed because the AESO board only received written submissions from three stakeholders. The AESO stated participants in the budget review process included representatives of small consumers, municipalities, industrial consumers, and generators, with an opportunity for each of these stakeholders to make presentations directly to the AESO board should they see fit to do so. Further, more than three stakeholders participated in the budget review process and provided written comments, which were responded to by AESO management and provided to the AESO board. Additionally, the opportunity to make presentations to the AESO board is provided to all stakeholders who participate in the budget review process. The AESO stated that simply because only three stakeholders took advantage of this opportunity, it should not be assumed to be indicative of a flaw in the process, rather it may suggest that participants were satisfied with the reasonableness and appropriateness of the AESO's business plan and budget proposal.²⁵

61. With respect to the AESO's own administrative costs, the AESO resisted the CCA suggestion that the AESO board should be directed in the manner in which it assesses these costs. The AESO noted that Section 8(9) of the *Electric Utilities Act* requires the AESO board, in carrying out its duties, responsibilities, and functions, to "exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances." The AESO submitted that the AESO board may avail itself of any approaches it considers appropriate to

²⁴ *Transmission Regulation*, Section 46(1).

²⁵ Exhibit No. 402.02, AESO reply argument, paragraph 4.

satisfy the requirements established by the *Electric Utilities Act*. Furthermore, the AESO argued that Section 3(2) of the *Transmission Regulation*, tasked the AESO, not the Commission, with establishing the practices respecting the approval of these costs by the AESO board.

62. The AESO submitted that it would be inappropriate to direct the use of benchmarking studies or independent external experts in the absence of evidence that costs or expenses approved by the AESO board are unreasonable. Furthermore, given the opportunity afforded to all stakeholders to make presentations to the AESO board, it was misleading to suggest that the AESO board has no information before it from sources other than AESO management. The AESO also suggested that in the event a market participant is dissatisfied with the AESO board's decision, the appropriate forum in which to challenge the AESO board's decision was through the dispute resolution process outlined in ISO Rule 103.2.

63. Additionally, the AESO responded to the CCA's concern that the AESO board, in approving its 2013 budget, termed the budget "reasonable" rather than "prudent." The AESO submitted that, in approving forecast costs, the AESO board must act in accordance with the responsibilities established by the *Electric Utilities Act* and that it was unwarranted to suggest that the AESO board may have ignored prudence considerations. The AESO submitted the essential question before the Commission regarding administrative costs, lines losses costs, and ancillary services costs is whether those forecast costs were approved by the AESO board in accordance with its responsibilities under the act. If so, these costs are deemed prudent under Section 48 of the *Transmission Regulation*. Where the AESO's administrative costs are concerned, if approved by the AESO board, they are presumed to be prudent unless an interested person satisfies the Commission that those costs are "unreasonable." The AESO stated the CCA's concerns in this regard should be dismissed by the Commission.

64. Finally, the AESO submitted that it would be more appropriate for the CCA to participate in the existing budget review process to address any concerns it may have with respect to the costs approved by the AESO board, rather than raising such concerns after the costs have already been approved.

Commission findings

65. The AESO board has both the responsibility and the authority under the *Electric Utilities Act*²⁶ and the *Transmission Regulation*²⁷ to approve the quantum of ancillary services costs, line loss costs and the AESO's own costs. The Commission's role in reviewing these costs in a tariff proceeding is limited.

66. As explained in Section 3.1 of this decision, the legislation establishes a scheme in which costs approved by the AESO board are generally not reviewed by the Commission in tariff proceedings (other than the AESO's own administrative costs on a limited basis). The rationale for this limited review in tariff proceedings is premised on two factors: (1) that market participants will have an opportunity to engage in consultation with the AESO regarding these costs and (2) that, for certain of these costs, the AESO has been directed to create a rule, in which case, market participants have an opportunity to bring forward objections or complaints to

²⁶ Section 30(4).

²⁷ Sections 46, 48(1) and 48(2).

the Commission regarding the rule. Additionally, Section 26 of the *Electric Utilities Act* enables any person to make a complaint to the Commission regarding the conduct of the AESO.

67. Section 121 of the *Electric Utilities Act* requires the Commission, when considering whether to approve a tariff application, to ensure, *inter alia*, that the tariff is just and reasonable and that the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any enactment or law. Consequently, the Commission considers that in approving an AESO tariff, it must be satisfied that the AESO has complied with the legislative requirements imposed on it to consult as directed by the *Transmission Regulation*.

68. Section 3 of the *Transmission Regulation* requires the AESO not only to consult with market participants who are “likely to be directly affected” by the AESO board’s approval of these costs, but also to establish rules or practices with respect to the approval of costs by the AESO’s board. The AESO outlined its practice related to its consultation and further indicated that if a market participant was dissatisfied with an AESO board decision it could avail themselves of the dispute resolution process provided for in Section 103.2 of the ISO Rules.

69. There is no question that the AESO engaged in consultations. The issue is whether the consultation that took place satisfies the requirements of the *Transmission Regulation*. With respect to the consultation process outlined by the AESO, the Commission accepts the AESO’s evidence that materials from the cost consultation working group were usually posted on the AESO’s website, that other stakeholders were invited to review those materials and provide comments to the AESO or working group members, that no stakeholders were excluded from participating in the general stakeholder meetings, and that all stakeholders had the opportunity to contact the AESO at any time and discuss its tariff application. Further, the Commission accepts the AESO’s evidence that the AESO also met individually with stakeholder groups or representatives who requested the opportunity to discuss informally its tariff application. The Commission finds the consultation process to be sufficient to satisfy the legislated consultation requirements imposed on the AESO regarding these costs. With respect to the principal concerns of the CCA, the Commission notes that there is ample opportunity for the CCA to play a more pro-active role in the AESO budget review process.

70. The Commission also considered the CCA’s request that the AESO be directed to explain in its compliance filing why the approval from its board used the word “reasonable” rather than “prudent.” Section 46(1) of the *Transmission Regulation* uses both “prudent” and “unreasonable” and in Section 48(1) of the *Transmission Regulation*, states that a reference in the *Electric Utilities Act* to “prudent” or “appropriate” in relation to the AESO’s costs for ancillary services and line losses means those costs that have been approved by the AESO board. The Commission accepts the AESO’s testimony that the AESO board has approved the forecast for these costs. Accordingly, the request of the CCA for a further explanation in the compliance filing is denied.

71. With regard to the request of the CCA that the Commission direct the AESO to use benchmarking studies or independent external experts as part of the AESO board budget review and approval process, the CCA can present its proposals directly to the AESO through its consultation procedures. The Commission will not provide a specific direction to this effect.

72. An interested party may, pursuant to Section 46(1) of the *Transmission Regulation*, bring forward a case that the AESO’s own administrative costs are unreasonable. As the substance of the CCA’s concern appears to be related to the robustness of the process followed by the AESO

in securing its board's approval, and not that the AESO's own administrative costs are unreasonable, the Commission has not made any finding that the AESO's own administrative costs are unreasonable. The onus is on the interested party to satisfy the Commission that the AESO's own administrative costs are unreasonable and the CCA has not provided any evidence that would satisfy the Commission in this regard.

4 2014-2016 cost causation study

73. Decision 2010-606, the decision on the AESO's most recent comprehensive tariff application, included the following direction:²⁸

128. ... The Commission directs the AESO to file an updated Transmission Cost Causation Study along with its next major tariff application, no later than March 31, 2013.

74. The AESO included a 2014-2016 cost causation study prepared by LEI as part of its application and stated that the results of the updated transmission cost causation study and updated point of delivery cost function are incorporated into the design of demand transmission service (DTS) rate and other rates.²⁹

Commission findings

75. On November 27, 2013, the Commission issued Decision 2013-421 approving the negotiated settlement agreement with respect to the AESO's 2014-2016 cost causation study. In the negotiated settlement agreement, the AESO indicated that the settlement had been unanimously supported and that no issues with respect to the 2014-2016 cost causation study remained unresolved.³⁰

5 Rate design

76. In Section 5.2 of the application, the AESO stated that the 2014-2016 cost causation study prepared by LEI generally followed the same methodology used in the prior cost causation studies which consisted of:

- first functionalizing capital costs into bulk system, regional system, and point of delivery functions
- then functionalizing operating and maintenance costs into similar functions
- finally classifying bulk system and regional system costs into demand-related and energy-related components

²⁸ Decision 2010-606, paragraph 128.

²⁹ Exhibit No. 26, revised tariff application, paragraphs 148-150.

³⁰ Exhibit No. 120.02, paragraph 9.

5.1 Bulk system costs

77. The vast majority of bulk system costs were classified as demand-related. This classification was agreed to by the parties in the negotiated settlement agreement that was approved by the Commission in Decision 2013-421.

78. As the rate design to be employed for the collection of these costs was excluded from the scope of the negotiated proceeding, the AESO proposed the continued use of the 12 coincident peak methodology (12 CP) as the billing determinant for the collection of bulk system line costs.

5.1.1 Allocation of bulk line costs

79. In its intervenor evidence, the CCA proposed an alternative methodology for the collection of bulk system costs. The CCA proposed that the billing determinant for the bulk system be the higher of the hourly coincident peak demand during the month and 85 per cent of the customer's peak demand in any one hour during the peak period between Hour Ending 7 to Hour Ending 23.³¹ The CCA argued this methodology would send the appropriate signal that demand established at the time of the coincident system peak are important while demand established during hours outside the system peak remain important, although to a lesser degree. This approach would recognize that, on average, the room available for load diversity on the bulk system is limited to about 118 per cent ($1/0.85$) assuming an average system load factor of 85 per cent.

80. The CCA maintained that for the Alberta interconnected electric system, although load flows in every hour are important, the peak period load flows are relatively more important than off peak load flows with respect to causing capacity additions. The CCA argued this stands to reason because load flow studies that are used for planning purposes are conducted using system elements and stress on the system elements is assessed as load increases occur, with the onset of the peak period.³² Accordingly, the CCA suggested it would be appropriate to apply 85 per cent of non-coincident peak (NCP) demand during peak hours.

81. A key objective of the 12 CP methodology was to achieve a flatter Alberta internal load profile by providing customers with an incentive to shift their load outside the monthly system coincident peak hours, thereby facilitating efficient use of the system; efficient use of the system, in turn, was expected to result in the deferral of future capacity additions as load growth occurred. However, the CCA argued that, if significant peak demands established by customers in hours other than the monthly system coincident peak hours were also to contribute to bulk system capacity additions, due to the high load factor and geographically dispersed network nature of the bulk transmission system, then the investment deferral benefit from shifting load outside the system coincident peak hours may not be fully realized.

82. The CCA stated that the Alberta bulk system fits the profile of a high load factor network system. As such, there would be less capacity room for load shifting outside system peak hours because the average load is high relative to the system peak. As a network bulk system with different elements of the system peaking at different times, certain localized peaks may not coincide with the monthly system coincident peak. Shifting too much load outside the monthly system peak hours may be counter-productive for the Alberta system from the point of view of

³¹ Exhibit No. 148.01, CCA evidence, paragraph 52.

³² Exhibit No. 148.01, CCA evidence, paragraph 47.

the efficient use of the system, particularly if such loads could in turn cause new capacity additions. The question then is how much is too much load shifting and how to determine the limits to such load shifting. The CCA reviewed the average load factor of the system, the findings of transmission planners in the 2007 GTA and the degree of load diversity on the system to propose some answers.

83. The CCA noted that the average system load factor from 2008 to 2012 was 84 per cent, which provided an indication of the room available for load shifting. With an 84 per cent system load factor, the room for load diversity would be approximately 119 per cent ($1/0.84$). As well, the average line loading of 111 per cent on a monthly basis, identified by the AESO at the time of the 2007 GTA, provided an indication of the room for diversity that was available on the bulk system, on average, for load shifting and suggests that if this level of load diversity were exceeded, there may be a need for capacity additions from a planning perspective.

84. The CCA indicated that the average diversity factor (ratio of NCP/12 CP demands) provided an indication of the extent to which load shifting to hours outside the system peak hours was occurring. The CCA presented a table in its evidence, Table 4,³³ which indicated a diversity factor range of 147.5 per cent to 151.4 per cent from 2010 to 2014. The CCA maintained, this high diversity factor indicated that a significant portion of the NCP demands were established during hours outside of the 12 monthly system peak hours. The high diversity factor also indicated the NCP demands established outside the 12 monthly system peak hours were significantly higher than those established during system peak hours.³⁴

85. While acknowledging that system coincident peaks are more important than the load in every hour, the CCA also stated the latter was important due to the high load factor of the Alberta system as well as the geographically dispersed network nature of the bulk system where different transmission elements are peaking at different times. The CCA suggested in such a system, although there was some room for load shifting to hours outside the system peak hours which results in load diversity in relation to the monthly system peak demands, there should also be appropriate price signals to indicate there is real potential for additional costs associated with a high degree of load shifting to hours outside the monthly system peak hours. CCA stated customers with a high diversity factor must be given the right price signals to indicate establishing high NCP demands outside the hours of monthly system coincident peak can and do contribute to additional bulk system costs from a planning perspective.³⁵

86. The AESO rejected the CCA's proposed methodology noting that it is based upon the rationale that, due to the claimed 85 per cent load factor on the bulk system and consequent limited diversity, there is the potential for load to avoid a coincident system peak while causing a peak on an individual transmission system element. The CCA had referred to the AESO's 2007 tariff application and information provided during that proceeding on loading of the bulk transmission system in support of its proposal. However, the AESO argued that the CCA had ignored an important aspect of the data from that proceeding, that it was based on the length-weighted average 240-kilovolt (kV) line load factor of 50.0 per cent in 2005 and 47.3 per cent in 2004, with the AESO recommending using the average of these two load factors, namely 48.6 per cent. The AESO stated the load factor of bulk system lines was not the system load

³³ Exhibit No. 148.01, CCA evidence, page 11.

³⁴ Exhibit No. 148.01, CCA evidence, page 11, paragraph 37.

³⁵ Exhibit No. 148.01, CCA evidence, page 14, paragraph 44.

factor of 85 per cent as suggested by the CCA, but was a significantly lower load factor of about 49 per cent. Accordingly, the AESO submitted that there is much more room for load diversity at the individual system element level than what the CCA has assumed.

87. Mr. Martin testified during the hearing that the 12 CP methodology is reflective of cost causation³⁶ and further, the methodology satisfies the rate design principles discussed at Section 5.2 of the application. Mr. Martin explained that the system was primarily planned on the basis of system peak, stating “I wouldn’t want to suggest that we have no concern about loading in other than coincident system hours, but, as I mentioned this morning, loading of individual transmission line elements is a consideration, but the system is primarily tested on their peak loading conditions.”³⁷

88. The AESO noted that, in argument, the CCA suggested a system load factor of 85 per cent, implying that “an uneconomic load is one that has about an 85% probability of causing system additions.” The AESO submitted this suggestion was unsupported by evidence. For example, when asked by Commission counsel whether it is likely that the load of an individual market participant would cause an addition to the bulk transmission system, the AESO stated that it considered it “doubtful that it would have an impact on the bulk system facilities.”³⁸ The AESO further explained that “the system is studied and developed under system peak conditions, which would be coincident peak in the CP terminology: winter system peak, summer system peak.”³⁹

89. The AESO further testified that on a networked system, “there are multiple services, and those combinations of services have an aggregate peak demand as well, which may not be seen by any individual line because a transmission system is a heavily networked system.”⁴⁰ The load on an individual bulk system element resulted from aggregate loads of many services and the CCA’s suggestion that an individual service can cause a system addition due to off-peak loading of an individual system element would require that other loads affecting flow through that element would also be near or above the levels experienced during system peak hours. The AESO submitted such load coincidence outside of system peak hours is unlikely, and there was no evidence demonstrating that the probability of such load coincidence on an individual system element is 85 per cent in hours outside of system peak hours.

90. The AESO also raised concerns about the potential reduction to the effectiveness of the price signal that is currently being provided through the 12 CP method were the CCA’s methodology accepted. As the AESO witness Mr. Martin explained in cross-examination, “if a market participant is able to respond to the coincident demand charge, they actually reduce their load during most of the peak hours in the month.”⁴¹

91. The AESO submitted that under the CCA’s proposed CP/85 per cent NCP method, a large industrial customer (i) would see less benefit from reducing load during hours near system

³⁶ Transcript, Volume 3, pages 441-442.

³⁷ Transcript, Volume 1, page 122.

³⁸ Transcript, Volume 3, pages 440-441.

³⁹ Transcript, Volume 3, pages 440-441.

⁴⁰ Transcript, Volume 1, page 41.

⁴¹ Transcript, Volume 3, page 443.

peak; (ii) make less effort to reduce its loads during hours near system peak; and therefore (iii) potentially contribute to higher peak demands on the transmission system.⁴²

92. The AESO further noted that in response to information request AUC-CCA-5, the CCA proposed to expand its proposal by incorporating a regional system peak component into its proposed billing determinant for bulk system costs. The AESO claimed that the CCA's rationale for adding a regional system peak component was that it "would recognize that regional planning is designed to meet regional peaks."⁴³ The CCA acknowledged, however, that "adding a third component to the bulk system rate design may add to the administrative complexity of the rate."⁴⁴

93. The AESO submitted that adding a regional system peak component to the bulk system charge would further reduce the effectiveness of the price signal currently provided through the 12 CP method. Moreover, there was no evidence on the record in this proceeding that the approximately 49 per cent load factor for bulk system lines does not sufficiently accommodate regional peaks as well as coincident system peaks. Accordingly, the AESO submitted that the CCA's expanded proposal for a CP/RP/85 per cent NCP method for bulk system cost recovery should also be rejected by the Commission.

94. The ADC, DUC and IPCAA each supplied argument that was generally supportive of the AESO's current 12 CP methodology.

95. The ADC noted that the current methodology had been fundamental in investment decisions by their members to curtail production in order to reduce the strain on the transmission system during peak load.

96. The ADC considered the use of the 12 CP methodology as reflective of the load diversity on the system. Although the peak demands on the AESO system occur during the winter and summer peak periods, customers' contributions to monthly peaks in all other months outside of the peak summer and winter periods recognize the diversity in load, diversity factor of load, and other factors. As such, ADC submitted the 12 CP allocation factor not only reflects the most direct measure of cost causation and customers' load characteristics, but also encompasses the diversity of load on the system.

97. The ADC maintained that the CCA had not provided any evidence that any current or planned transmission investment was being caused by customer non-coincident peaks, stating the record was that bulk transmission is planned on the basis of system peak. The ADC maintained that the 12 CP methodology is inherently fair to all users, large or small, because the method aligns most closely with how the cost for the bulk system is incurred. The ADC also noted the Commission agreed that matching cost causation with cost recovery is inherently fair when it ruled in the 2007 GTA that rates would be fair so long as they are cost-based.⁴⁵

⁴² Exhibit No. 366.01, AESO argument, page 31.

⁴³ Exhibit No. 216.01 AUC-CCA-5.

⁴⁴ Exhibit No. 216.01 AUC-CCA-5.

⁴⁵ Decision [2007-106](#): Alberta Electric System Operator, 2007 General Tariff Application, Application No. 1485517, December 21, 2007, page 14.

98. The ADC noted that the CCA, in its argument, referred to Exhibit No. 285 which claimed to show an on-peak system load factor of 92 per cent for 2013. The ADC accepted the AESO's response to the CCA's continued claims of high load factors on the bulk transmission system, when the AESO clarified in its argument that the CCA misinterpreted loading data from the AESO's 2007 tariff application:

In other words, the load factor of bulk system lines is not the system load factor of 85% as suggested by CCA, but is a significantly lower load factor of about 49%. Accordingly, the AESO submits that there is much more room for load diversity at the individual system element level than what the CCA has assumed.⁴⁶

99. The ADC also noted that the CCA had presented an airline ticket price analogy in its argument, asserting that off-peak flights are not 100 per cent free and if a significant number of customers move into the off-peak period, new peak flight periods can be established. The ADC stated any reader can agree that off-peak power is also not free. Also, should new AESO system peaks be established during the historical non-peak period, as the CCA's analogy posits, these new peaks would become the billing determinant for the bulk transmission system costs. If significant load shifting pushed the typical monthly peak reading down, and created a new system peak at another time, all customers would then be billed on that new system peak. The ADC stated the current 12 CP methodology is intended to capture the effects of such significant load shifting.

100. The DUC supported the arguments of the ADC stating that the evidence on the record is that AESO customers tend not to shift load, but rather reduce load in response to high pool prices and, for a few customers, to reduce load during times of the anticipated monthly peak demand. The AESO stated that "there's not a whole lot of opportunity for load shifting,"⁴⁷ which was then confirmed by the ADC.⁴⁸ The DUC testified that its members do not load shift to try to avoid bulk system demand charges.⁴⁹

101. The DUC noted that the CCA had characterized the rate effect of its proposal as modest and that it was unlikely to cause any rate stability concerns.⁵⁰ The DUC disagreed, stating that a 96 per cent rate increase⁵¹ is not modest and that the CCA proposal would definitely result in rate shock for dual use customers.

102. The DUC also maintained that the CCA provided no evidence to suggest that load shifting has or will result in system additions.⁵² While "any amount of load occurring outside of the 12 CP hours are cost free" from a bulk system demand cost recovery perspective, load occurring outside of the 12 CP hours still pays DTS Regional and POD charges. Further, as clearly indicated by the DUC witness, dual-use customers do not try to avoid the 12 CP hours.⁵³

A. My members do not take those actions.

⁴⁶ Exhibit No. 366.01, AESO argument, paragraph 100.

⁴⁷ Transcript, Volume 1, page 123.

⁴⁸ Transcript, Volume 4, page 552.

⁴⁹ Transcript, Volume 4, pages 578-579.

⁵⁰ Exhibit No. 371.02, CCA argument, paragraph 56.

⁵¹ Exhibit No. 371.02, CCA argument, paragraph 56.

⁵² Exhibit No. 362.01, DUC argument, page 7, line 21 to page 8, line 21.

⁵³ Transcript, Volume 4, page 579, lines 1-16.

Q. They don't try to avoid system peak?

A. No.

Q. Why is that, sir?

A. To the extent that they may reduce their load, they are doing it to avoid high pool price periods, which has a much larger economic benefit than trying to avoid the bulk system demand charge.

Most of my clients, dual-use customers, are cogeneration customers, and the generation equipment behind the fence, first and foremost, is to run process heat to industrial process. When they take energy from the grid, it's typically when the generation is down.

So it's their operations that would dictate when they would take energy from the grid instead of peak, not any actions trying to avoid bulk system demand charges.

103. The DUC submitted that dual use customers pay an appropriate level of bulk system demand costs. While in some months they may avoid the charge if the on-site generation is greater than the on-site load, in other months they may pay the full bulk system demand charge if the generator is off-line. The current 12 CP rate design reflects cost causation and sends appropriate price signals to AESO customers who can reduce load around the times of the anticipated monthly peak demand.

104. IPCAA supported the arguments of the ADC and the DUC. IPCAA pointed out that for a customer to have a higher post-shift load, the customer would have to have spare production capacity. The high load factors of industrial customers are evidence that such spare capacity does not exist. IPCAA noted the testimony of Ms. Chekerda of the ADC who stated with respect to her members' loads:⁵⁴

I think for the most parts the loads are – or the load profiles are relatively flat. The key thing is that the members have invested into facilities that provide them some more flexibility to respond to pool prices, whenever they may occur. So, it's more a load reduction, I would say, than creating a new peak at another time of the day.

105. IPCAA maintained that a second major weakness of the CCA's proposal to provide a price signal with respect to load shifting is the fact that the actions of individual customers are unlikely to effect the bulk transmission system. IPCAA noted the testimony of Mr. Martin:

So, yes, most likely to affect the point of delivery. Somewhat likely to affect the regional system facilities. To my mind, doubtful that it would have an impact on the bulk system facilities.⁵⁵

106. IPCAA stated a further weakness in the CCA proposal was the fact that there is no problem with the current tariff design and operation. IPCAA noted Mr. Martin's testimony that the existing rate design appropriately allocated costs based on cost causation:⁵⁶

Yes. The 12CP method seems to reflect one of the major considerations for planning and developing the transmission system. The system is studied and developed under system peak conditions, which would be coincident peak in the CP terminology: winter

⁵⁴ Transcript, Volume 4, page 552.

⁵⁵ Transcript, Volume 3, page 441.

⁵⁶ Transcript, Volume 3, pages 441-442.

system peak, summer system peak. And it charges customers for the cost of the system based on their contribution to that system peak. If a market participant contributes a greater share to that system peak than other market participants, then the contribution of the greater share should lead to greater costs being charged. A perfectly flat load profile that an industrial customer can sometimes almost achieve, contributes 100 percent of the load to that system peak and pays a fair share of the bulk system based on that contribution. I think the issue is for market participants who can respond to the system peak signal and be able to reduce their load during the periods in which system peak usually occurs. So those customers end up paying somewhat less towards the bulk system because they're not on peak. So that seems like a reasonable outcome to me and a fair reflection of cost causation to the allocation of cost. Doesn't seem like favouring one party over the other.

107. Finally, IPCAA asserted that the CCA appeared to have added a regional peak component to its proposed billing determinant for bulk system charges. IPCAA noted that there are two important distinctions between regional peak demands (and the system peak). They are time of year of the peaks and time of day of the peaks. With respect to the first, time of year of regional peaks, IPCAA noted Mr. Retnanandan was cross-examined on this topic by Mr. Secord.⁵⁷ Mr. Retnanandan agreed that, at the time of the 2010 AIS peak, the regional peaks were not significantly different from their highest annual values.⁵⁸

108. With respect to the second point, the time of day of the regional versus AIS peaks, IPCAA noted Mr. Secord presented a figure to the CCA in cross examination, presenting regional and AIS load as a fraction of each region's annual peak on the day of the AIS annual peak. IPCAA maintained it was obvious from the figure that the load shapes of the various regions were very similar to the AIS load shape (except for the NW region, where the load profile reflected the shedding of price responsive load). Given the similarity of regional and AIS peaks in terms of time of year of peak and hour of day of peak, IPCAA submitted there is nothing to be gained from the CCA's proposal to add regional peak demand to the list of billing determinants for bulk transmission.

109. The CCA responded to the criticisms of its proposed methodology in its argument and reply argument submissions. The CCA stated that planning takes into account the scheduled and reasonably expected unscheduled outages at the level of system elements, noting that the NERC requirement that electric systems supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. The CCA claimed that this suggested that planning at the system element level is important from a planning perspective and that high hourly loads outside system peak hours can be considered uneconomic if they trigger future plant additions at the level of system elements. Accordingly, it is the effect of uneconomic loads at the level of system elements, rather than the effect on the entire system that is important in considering bulk system rate design.

110. Second, system planning took into consideration all hours including system light conditions. Since load, generation and interchanges are constantly changing in response to customer needs and the need for load and generation to balance instantaneously, the source and

⁵⁷ Mr. Secord was reviewing the table in Exhibit No. 304.01 with Mr. Retnanandan.

⁵⁸ Transcript, Volume 6, page 869.

load for different transmission elements are also changing in a dynamic manner. In accordance with the requirement that the system must meet the aggregate demands and energy requirements of customers at all times, the CCA maintained the AESO not only assesses whether the system is adequate to meet peak load conditions, but also the adequacy of the system during system light conditions.

111. Third, the bulk system lines are loaded close to the system peak demands in several hours outside of the system peak hours. The CCA referred to Exhibit No. 285.01 which, it asserted, indicates on-peak system load factors have been increasing since 2009. The on-peak system load factor is an indicator of the relationship between the average of the 12 coincident peak demands and the average load during on-peak hours. The 92 per cent on-peak load factor shown in Exhibit No. 285.01 suggests the average load during the peak hours is close to the average of the 12 monthly system peaks. The CCA suggested the planning of the system indicated different system elements may be operating at or near their maximum loading and/or stability ranges at different times. Hence, the incidence of loads outside the system peak hours can result in uneconomic load occurrence potentially giving rise to future plant additions depending on the location, quantum and timing of the load incidence.

112. In view of the planning considerations noted above, the CCA recommended that there be a price signal for loads occurring outside system peak hours to recognize the probability that such loads can result in plant additions. The CCA evidence suggests system load factor is one possible broad indicator of the relationship between the loads during peak hours and the loads outside of peak hours and an indicator of the amount of room available for economic load shifting. The 85 per cent system load factor reflects the relationship between the average of the 12 coincident peak demands and the average load during all hours. In the CCA's submission, use of the average of 12 monthly system coincident peaks for this load factor calculation is appropriate since it captures changes in the transfer capability of system elements with changing seasons. The 85 per cent of NCP demand component would allow load diversity of up to 118 per cent.

113. The UCA supported the CCA's position that recovering demand-related bulk system costs solely on the basis of a customer's demand during the monthly system peak hour may not reflect cost causation.

114. The UCA submitted that there is a real risk that customers will try to game a 12 CP billing determinant. Even at the present time, the AESO indicated that some customers appear to be trying to avoid the system peak for transmission charges, even when the pool price is not particularly high.⁵⁹ The UCA noted the ADC had acknowledged that some of its members have made investments to be able to reduce load during on-peak times, in addition to during high pool prices.⁶⁰

115. The AESO responded to the UCA's claim arguing that there was no evidence on the record in this proceeding addressing whether this is a real risk or what magnitude of risk there might be that a market participant would be able to use the bulk system in all but the single system peak hour of a month. The AESO argued that the UCA's reliance on the AESO's 2007 evidence ignored the AESO's statement that any prior concerns it may have had in respect of a

⁵⁹ Transcript, Volume 1, page 121, lines 5-15.

⁶⁰ Transcript, Volume 4, page 544, lines 13-17.

customer's ability to avoid a single hour and therefore avoid all transmission cost had not materialized.⁶¹ The AESO further stated:⁶²

[T]here are sites that do reduce load in the period where the coincident system peak usually occurs. And they're right in many months of the year but not all months of the year. So it seems like load customers that are able to are making specific effort to avoid the coincident system demand and not just limiting it to a single hour in the month.

116. The ADC also responded to the submissions of the UCA in its reply argument submission. The ADC stated that the UCA failed to recognize that large customers incur significant costs to curtail demands. They will incur those costs to create savings, but only if the savings justify the costs. Actual customers of the AESO cannot, in practice, know with exact certainty which hour of the billing month will be the system coincident peak. In practice, customers often reduce demand multiple times throughout a month, in an effort to avoid high pool prices and to reduce their demand-related transmission costs. These behaviours are the exact responses most beneficial to the Alberta market and the AESO transmission system. These customers should be properly rewarded. On the other hand, this price responsive behaviour would not be encouraged if the proper rate-design price signals did not exist.

117. The DUC responded to the UCA in a similar fashion. The DUC maintained the evidence on the record was that it is very difficult for customers to simply avoid the single monthly peak. The statistics published by the AESO in real time do not correlate to the monthly peak demand billing determinant the AESO uses to determine the monthly peak time period.⁶³ The actual billing determinant used is not available until the following month, long after the fact. The monthly system peak could be influenced by factors that a customer may be able to predict like weather, but the monthly system peak could also be set by an on-site generator trip, which no one could predict. The UCA's suggestion that large industrial customers can avoid the single monthly peak is neither realistic nor practical as the DUC witness has testified that dual-use customers do not even try to avoid the monthly system peak.⁶⁴

Commission findings

118. The extent to which there may be a need to modify the billing determinant for the collection of bulk system demand costs is influenced by the amount of diversity on the bulk system. The AESO and the CCA have differing views as to what that diversity amount is. The AESO considers there to be considerably more diversity on the bulk system than the CCA does.

119. When asked under cross examination if it was likely that the load of an individual market participant would cause an addition to the bulk system, the AESO's witness, Mr. Martin explained:⁶⁵

I do think it's more likely that an individual -- or most likely that an individual customer's changes to load characteristics would result in changes to the point of delivery facilities. Those are designed to meet the needs of individual customers or occasionally multiple

⁶¹ Transcript, Volume 1, page 118.

⁶² Transcript, Volume 1, pages 119-120.

⁶³ Transcript, Volume 1, page 124, line 21 to page 127, line 16.

⁶⁴ Transcript, Volume 4, page 579, lines 1-16.

⁶⁵ Transcript, Volume 3, pages 441-442.

customers served from a single substation. So, clearly, the requirements of the individual customer affect that. Moving up the system, we go to the regional system, where facilities are shared in a smaller geographical area among multiple customers, maybe ten or so customers. In that case the characteristics of a single customer can have an impact. It depends on the nature of that customer and the nature of the other customers and the particular configuration of the regional system. As we've talked about, that's typically why we have an average regional charge to try smooth out all of those individual characteristics and reflect the nature of the service being provided as opposed to a specific facility. So, yes, most likely to affect the point of delivery. Somewhat likely to affect the regional system facilities. To my mind, doubtful that it would have an impact on the bulk system facilities.

120. On the basis of this testimony, the Commission accepts the AESO's evidence that there is considerably more diversity on the bulk system than the 85 per cent load factor proposed by the CCA. The Commission notes that the specific percentage load factor was provided in the AESO's argument submission in response to the CCA's evidence. In concluding that there is substantial diversity on the bulk system, at least more than the 85 per cent load factor proposed by the CCA in its evidence, the Commission has relied only on the AESO's evidence, not on its argument submissions, and, in doing so, does not make any finding regarding what the specific percentage load factor for the bulk system may be.

121. With respect to the CCA's contention that its proposal would send an appropriate price signal to customers, the AESO explained that under the proposal, a large industrial customer (i) would see less benefit from reducing load during hours near system peak; (ii) make less effort to reduce its loads during hours near system peak; and, therefore, (iii) potentially contribute to higher peak demands on the transmission system.⁶⁶ The AESO's witness, Mr. Martin, also explained in cross-examination, "if a market participant is able to respond to the coincident demand charge, they actually reduce their load during most of the peak hours in the month."⁶⁷

122. The AESO also noted that the CCA proposed to incorporate a regional component into the bulk system charge. The AESO also stated that adding a regional system peak component to the bulk system charge would further reduce the effectiveness of the price signal currently provided through the 12 CP method. Moreover, there was no evidence on the record in this proceeding that the load factor for bulk system lines does not sufficiently accommodate regional peaks as well as coincident system peaks.

123. The UCA has claimed that parties would be able to game the 12 CP billing determinant, claiming the AESO indicated that some customers appear to be trying to avoid the system peak for transmission charges, even when the pool price is not particularly high.⁶⁸ The AESO's evidence on this issue was as follows:

MR. MARTIN: I haven't specifically looked at trying to correlate reductions in load to pool price versus anticipation of high system demand, but some of the individual sites I've looked at do reduce demand during hours when pool price doesn't seem particular high, and they've said they are trying to avoid system peak. So we assume that at least for some customers they're trying to avoid the system peak for transmission charges.

⁶⁶ Exhibit No. 366.01, AESO argument, page 31.

⁶⁷ Transcript, Volume 3, page 443.

⁶⁸ Transcript, Volume 1, page 121, lines 5-15.

Q. So the tariff is working?

A. MR. MARTIN: Inasmuch as market participants are responding to the price signal, yes.

124. The Commission considers that when viewed in context, Mr. Martin is not stating customers are gaming the system. Rather, they are responding to the price signal appropriately – reducing load to avoid system peak and thereby reducing the need for bulk system expansion. The Commission agrees with the assessment of the AESO that the response of market participants to the coincident peak demand price signal demonstrates the effectiveness of the rate design rather than providing evidence of gaming the billing determinant.

125. The Commission also notes the explanation of the ADC in its reply argument that large customers incur significant costs to curtail demands. They will incur those costs to create savings, but only if the savings justify the costs. Actual customers of the AESO cannot, in practice, know with exact certainty which hour of the billing month will be the system coincident peak. In practice, customers often reduce demand multiple times throughout a month, in an effort to avoid high pool prices and to reduce their demand-related transmission costs. These behaviors are the exact responses most beneficial to the Alberta market and the AESO transmission system.

126. For all of the above reasons, the Commission rejects the CCA's proposal to incorporate an NCP component into the bulk system demand charge.

127. With respect to the AESO proposal to continue the use of the 12 CP method, the Commission notes the testimony of Mr. Martin that the existing rate design appropriately allocates costs based on cost causation:⁶⁹

Yes. The 12CP method seems to reflect one of the major considerations for planning and developing the transmission system. The system is studied and developed under system peak conditions, which would be coincident peak in the CP terminology: winter system peak, summer system peak. And it charges customers for the cost of the system based on their contribution to that system peak. If a market participant contributes a greater share to that system peak than other market participants, then the contribution of the greater share should lead to greater costs being charged. A perfectly flat load profile that an industrial customer can sometimes almost achieve, contributes 100 percent of the load to that system peak and pays a fair share of the bulk system based on that contribution. I think the issue is for market participants who can respond to the system peak signal and be able to reduce their load during the periods in which system peak usually occurs. So those customers end up paying somewhat less towards the bulk system because they're not on peak. So that seems like a reasonable outcome to me and a fair reflection of cost causation to the allocation of cost. Doesn't seem like favouring one party over the other.

128. Elsewhere, Mr. Martin also explained that the system was primarily planned on the basis of system peak, stating "I wouldn't want to suggest that we have no concern about loading in other than coincident system hours, but, as I mentioned this morning, loading of individual

⁶⁹ Transcript, Volume 3, pages 441-442.

transmission line elements is a consideration, but the system is primarily tested on their peak loading conditions.”⁷⁰

129. The Commission accepts that the system is primarily planned on the basis of system peak and that the 12 CP method is a reasonable method to collect bulk demand charges. The AESO’s proposal to continue to use the 12 CP method is approved.

5.2 Regional system costs

130. At Section 6.3.1 of the application, the AESO proposed to maintain the structure of the demand transmission service Rate DTS as approved in the AESO’s 2010 tariff proceeding, including the non-coincident peak capacity based charge for the allocation and collection of regional system demand charges. The billing capacity charge also includes two-year historical non-coincident peak (ratchet) and contract capacity components.

5.2.1 Distance based regional system charge

131. In its evidence, the DUC proposed an alternate rate design from that proposed by the AESO in its application. The DUC stated that the current rate design does not reflect the diversity of AESO customers and the costs they impose on the regional system. For example, customers that are fed directly from the bulk system at 240 kV theoretically do not use the Regional system, whereas a customer that is located 200 kilometres (km) from the nearest 240-kV line would use proportionately more of the Regional system. To reflect the diversity of the system better, the DUC proposed a rate design that would collect 50 per cent of the regional demand costs using a demand-distance (megawatt (MW)-km) based charge.

132. The DUC claimed there are potentially two key drivers for regional demand costs, distance and capacity. A point of delivery (POD) located further away from the bulk system will utilize more regional facilities than a similar sized POD located closer to the bulk system. Larger PODs require more and/or larger regional facilities to be built and reserved for their use than a smaller POD that is the same distance from the bulk system. The DUC claimed the proposed MW-km charge would ensure that all customers pay a portion of the regional system-related costs.

133. Approximately 63 per cent of the regional costs are related to transmission lines and 37 per cent of the regional costs are related to substations.⁷¹ Since the recovery of regional substation costs is not related to distance, a greater proportion of the regional costs should be collected based on demand or capacity based billing determinants and less on distance. Overall, the DUC’s proposed rate design would collect about 75 per cent of the regional system demand related revenue requirement based on capacity billing determinants and about 25 per cent based on distance billing determinants. The DUC relied on the information contained in DUC-AESO-007 to support its underlying premise that both distance and capacity are cost drivers for regional transmission lines.

134. In its evidence, the DUC used the AESO’s TASMO database to determine the distance from each POD substation to the nearest 240-kV source. It noted the smaller sized PODs tended to be located at distances further from the bulk system, with PODs serving larger loads (e.g.,

⁷⁰ Transcript, Volume 1, page 122.

⁷¹ Exhibit No. 120.05, Appendix B, Cost Causation Workbook, Tab Func Results 2014.

over 50 MW of billing capacity) generally located under the average distance of 50 km from the bulk system.⁷² The current regional billing demand charge was based on capacity and the information in Figure 8 of its evidence demonstrated a lack of correlation between distance and the AESO's proposed monthly regional demand charge (calculated based on proposed AESO 2014 DTS rate and 2012 billing capacities). As well, Figure 9 of its evidence revealed that PODs that use significantly greater portions of the regional system (i.e., utilize long lengths of regional lines and POD radial connections) can have significantly lower regional demand charges than PODs that are connected directly to the bulk system. The DUC asserted that these smaller PODs utilize a greater share of the regional system costs, even though they pay proportionality less and, from a cost causation perspective, the DUC asserted that this result suggests that the proposed tariff was not optimal.

135. To capture both the distance and capacity based cost drivers related to the regional demand costs, the DUC multiplied the Figure 8 distances by the average billing capacity for each POD and provided the MW-km billing determinants in Figure 10 of its evidence. An illustration of its modified DTS rate design was provided in Table 7 of its evidence.⁷³ Figure 11 provided a comparison of the regional demand charge options. When comparing these options, the DUC stated that using the distance-only option would result in several smaller PODs receiving large price increases while large PODs received large price reductions. Using a demand-distance determinant moderated this result while providing a stronger price signal for larger PODs that were located longer distances from the bulk system.

136. With respect to demand substation-related costs, the DUC asserted that the collection of 50 per cent of the regional demand costs based on billing capacity would ensure that the fixed costs related to substations are collected from customers in proportion to their capacity use of these substations. In addition, the capacity component of the proposed demand-distance billing determinant would also collect costs related to substations that are not related to the distance to the nearest 240-kV source.

137. The DUC maintained that its proposed rate design would not be difficult to implement, and suggested that the AESO could implement this rate design into the 2014 tariff between the time the Commission issues its initial decision and the effective date of the 2014 tariff. Further, the DUC provided a database query to calculate the distance from each POD to the nearest 240-kV substation using the AESO's TASMO database and was willing to share this software with the AESO to allow it to verify the results.

138. As further support for its proposal, the DUC also noted that POD-related assets have a distance-based component. Each POD has a substation and a notional radial connection to the regional system. For some customers, there is no radial connection (i.e., the substation is connected directly to the regional or bulk system) and for others there is a substantial distance from the substation to the regional system (i.e., a long radial connection). The distances presented in DUC's Figure 8 included the total distance from the substation to the bulk system, and included any radial connection. The DUC suggested its proposed rate design would also provide greater cost causation for the portion of the POD charges that are related to the collection

⁷² Exhibit No. 143.01, DUC evidence, Figure 8, page 25.

⁷³ Exhibit No. 143.01, DUC evidence, page 28.

of radial connection related costs, which, on average, represent about 21 per cent of the POD related costs.

139. Finally, with respect to isolated generation PODs, the DUC noted that there were only eight of them and suggested that incorporating the isolated PODs could be accomplished relatively easily. The isolated PODs have very high costs that are included in the AESO's revenue requirement. In the DUC's view, if these PODs were charged a higher DTS price, it would help send the correct economic signal to determine if an isolated POD should become grid connected.

140. The AESO opposed the proposal of the DUC, stating that the regional system charge is for system access service rather than for the specific facilities through which that service is provided. The AESO argued that Section 29 of the *Electric Utilities Act* requires the AESO to provide system access service on the transmission system to a market participant to exchange electric energy and ancillary services while Section 31 of the act requires the market participant to pay for that system access service. The AESO submitted that the rights and obligations established under the act relate to the service provided and paid for, rather than the facilities through which a connection to the transmission system is enabled.

141. The AESO explained in its testimony that "cost causation needs to reflect fairness, objectivity, and equity between customers and that each customer receives the same service and therefore should pay similar charges."⁷⁴ It also explained that "the regional system charge is averaged and shared over all consumers in the province because of its nature as a network charge."⁷⁵

142. The AESO described the regional system as a looped network that can supply each market participant's POD facilities through two or more electrical paths and noted that in its testimony, the DUC agreed that the multiple path network nature of the regional system provides reliability and capacity benefits that are valued by market participants. The AESO submitted that a distance billing determinant reflecting only the shortest path through the regional system ignored the reliability and capacity benefits that result from the alternate paths which, by definition, always exist on the networked regional system.

143. The AESO also stated a distance billing determinant did not provide a price signal that existing market participants could respond to. When it questioned the DUC witnesses on the changes to a distance billing determinant that would occur when a transmission development project extended the 240-kV transmission system, the DUC agreed that in such a case, the regional charge would decrease if the 240-kV system came nearer to a market participant, providing a benefit without the market participant responding to any price signal.⁷⁶ Further, the DUC acknowledged that any price signal provided by a distance billing determinant would be effective only for a new service.⁷⁷

⁷⁴ Transcript, Volume 1, page 95.

⁷⁵ Transcript, Volume 1, page 141.

⁷⁶ Transcript, Volume 4, pages 592-594.

⁷⁷ Transcript, Volume 4, pages 592-594.

144. The AESO further argued that a distance-based billing determinant contravenes Section 30(3) of the *Electric Utilities Act*, which provides:

30(3) The rates set out in the tariff

- (a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system,

145. The AESO maintained that a charge that varied depending on the shortest path through the regional system to the 240-kV bulk system facilities would clearly vary based on the location of a service on the transmission system. Although the DUC stated that, in its view, the legislative intent was that a difference could not result from locations “in different parts of the province,” such as urban or rural areas,⁷⁸ the AESO maintained that a plain reading of Section 30(3) of the act reveals that reference is made to location on the transmission system, not to location in the province or to distinctions between urban or rural areas.

146. Finally, the AESO considered that a distance based billing determinant is particularly inappropriate for isolated communities that are provided with electric service in accordance with the *Isolated Generating Units and Customer Choice Regulation*, AR 165/2003. The AESO explained isolated communities were not connected to the AIES, but pay the AESO as if they were being provided with system access service. Isolated communities were not connected to the interconnected electric system because the costs of such connections were prohibitive. It was more economical to supply electricity to isolated communities using isolated generating units due to the distances involved in a transmission connection. The AESO noted that the DUC proposed to charge an isolated community using a distance billing determinant for a theoretical connection when an actual connection has been found uneconomical. The AESO submitted that such an approach was unreasonable and could result in increased charges that would make a connection to the transmission system appear economical even though an isolated generating unit results in lower costs overall.

147. In summary, the AESO submitted that DUC’s proposed distance-based regional system charge should be rejected as it:

- (a) did not reflect the system access service being provided and instead reflects the facilities through which a connection is enabled;
- (b) did not recognize the reliability and capacity benefits that result from alternate paths that exist in the regional system;
- (c) did not provide an effective price signal for existing market participants;
- (d) contravenes Section 30(3) of the *Electric Utilities Act*; and
- (e) would result in unreasonable charges to isolated communities.

148. Both the CCA and the UCA also opposed the DUC proposal. The CCA stated that given the nature of the radial network system, it would not be appropriate to recover any regional

⁷⁸ Transcript, Volume 4, pages 588-589.

system costs using billing determinants based on a MW-km approach. Further, the use of a distance-based approach to recover costs of a network system would be a violation of the postage stamp rate principle. The UCA argued that the DUC proposal would be contrary to Section 30(3) of the *Electric Utilities Act*. The UCA also claimed that under the DUC's proposal, the functionalization of each transmission line as either bulk or regional could have a material effect on individual customer rates and that the DUC agreed that the functionalization of each transmission line as either bulk or regional would be more contentious than if the functionalization were only used for the purposes of the cost causation study. Further, the function of any given transmission line can change over time⁷⁹ and the DUC's proposal would be very difficult to administer.

149. The DUC responded to the criticisms of its proposal in its argument and reply argument submissions. In its argument, the DUC continued to advocate its proposal for a distance-based billing determinant in the regional component of the DTS rate, maintaining the current rate design does not reflect the diversity of AESO customers and the costs they impose on the regional system.

150. With respect to legislative considerations, the DUC argued that Section 30(3)(a) of the *Electric Utilities Act* requires the AESO tariff to be equally applicable to both DFOs and direct connect customers, regardless of where the customer is located in Alberta. The DUC did not interpret subsection (a) to mean that the AESO tariff cannot have a distance-based billing determinate. It suggested the term "rates" under Section 30(3) of the *Electric Utilities Act* should be interpreted to mean the rate at which a customer is charged. For example, under the current tariff, the local (regional) demand rate is \$1,243/MW/month. The DUC stated its proposed rate design does not set out different rates within the tariff. Rather, it was proposing a consistent rate for every AESO DTS customer. The resulting tariff charge for different DTS customers will vary, depending on each customer's billing determinants. Small customers pay less than large customers. The DUC argued that if the term "rates" was interpreted to mean tariff charges, then the existing tariff would be illegal as every AESO customer receives a different tariff charge.

151. The DUC noted that the AESO did not support the DUC proposal, stating that it believed the regional demand charge reflected the service provided. The DUC argued that this ignored cost causation and the important question of properly pricing the service, maintaining that if the use of the regional system is viewed as a service, then firstly, the cost of the provision of the service should be determined. The costs underlying this service are the revenue requirements related to the assets that provide the service and the regional system revenue requirement is directly proportional to the regional system rate base. The cost drivers for these assets are capacity and distance.

152. In reply argument, the DUC noted the AESO's assertion that a distance-based determinant fails to "reflect the reliability and capacity benefits of multiple regional system paths,"⁸⁰ suggesting that since the regional system is a "network," a distance based billing determinant was not appropriate and noted that it had conceded that the regional system was a network and that all AESO customers obtain benefits from the regional system, even those PODs that are directly connected at 240 kV to the bulk system. However, the DUC maintained the

⁷⁹ Transcript, Volume 4, pages 585-586.

⁸⁰ Exhibit No. 366.01, AESO argument, paragraph 118.

simple laws of physics included electricity taking the path of least resistance and the shortest distance through the regional system was a good proxy for the recovery of a portion of the regional system costs. The DUC reiterated that its proposal was that only 25 per cent of the regional demand costs should be recovered on a distance based billing determinant. All DTS customers would still make a significant contribution towards the regional demand costs via payments based on billing capacity. To the limited extent an AESO customer used portions of the regional system, other than the shortest path through the regional system, payments based on billing capacity would ensure equitable tariff treatment for all AESO customers.

153. The DUC also responded to the concerns of the AESO, the CCA and the UCA that the distance billing determinant would be applied to isolated generating units. The DUC explained that in the future, if an evaluation is made to determine if an isolated POD should be connected to the AIES, the AESO DTS tariff charges should not be used. Rather, the evaluation should compare the forecast annual cost of isolated generation to the forecast annual revenue requirement from a grid connection. The lowest overall cost addition to the AESO's revenue requirement should be chosen as it will result in the lowest AESO tariff rates. What the AESO actually charges an isolated POD, either under the current tariff or under the DUC's proposed rate, did not reflect the actual or hypothetical connection costs of an isolated POD. The DUC further explained that there are only eight isolated PODs, with a total DTS billing capacity of 11.1 MW, which is 0.1 per cent of the total DTS billing capacity.⁸¹ The DUC submitted that if there are any inappropriate price signals to the eight isolated PODs, the *de minimis* effect did not provide justification to dismiss the DUC's regional demand charge proposal, which more appropriately reflected cost causation for the vast majority of PODs that are connected to the AIES.

Commission findings

154. The DUC has proposed an alternative set of billing determinants for regional demand charges. In particular, the DUC has proposed the incorporation of a distance-related billing determinant that would result in approximately 25 per cent of regional demand charges being collected on the basis of a demand-distance (MW-km) based charge.

155. Before considering the merits of the DUC proposal, the Commission must determine whether the DUC proposal complies with the requirements of the *Electric Utilities Act* and in particular, Section 30(3) of the act.

156. The DUC has argued that its proposed charge would not violate the terms of the act and has interpreted Section 30(3) to require customers to be charged the same rate, which in the case of its proposed rate, it argues is satisfied because customers would be charged the same \$/km-MW. It would only be the total charges to any customer that would vary based partially upon its distance from the POD to the 240-kV source.

157. The AESO, as well as other parties, disagreed with the DUC. The AESO argued that a charge that varied depending on the shortest path through the regional system to 240-kV bulk system facilities would clearly vary based on the location of a service on the transmission system. The AESO stated a plain reading of Section 30(3) of the act reveals that reference is

⁸¹ Exhibit No. 265.05, AESO 2014-2016 Cost Causation Study Negotiated Settlement, Appendix E, Updated 2014 Bill Impact Analysis, tab E-3 Per POD, column C and column L.

made to location on the transmission system, not to location in the province or to distinctions between urban or rural areas.

158. Section 30(3) of the *Electric Utilities Act* states:

The rates set out in the tariff

- (a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and
- (b) are not unjust or unreasonable simply because they comply with clause (a).
(emphasis underlined)

159. As noted by the Supreme Court in *ATCO Gas & Pipelines v. Alberta (Energy & Utilities Board)*,⁸² the preferred approach to statutory interpretation is the modern principle of statutory interpretation set out by Elmer A. Driedger in *Construction of Statutes*, 2nd ed. at page 87:

Today there is only one principle or approach, namely the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament.

160. Turning, then, to an application of the modern principle of statutory interpretation of Section 30(3), a plain reading of the passage reveals that the act is referring to a person's location on the transmission system and states that a person's rate cannot be different due to that person's location on the transmission system, as evidenced by the words "as a result of the location of those system or persons on the transmission system." As the DUC's proposal would vary the person's rate as a result of that person's location on the transmission system, the distance from the 240-kV source, the Commission concludes that such a provision would be contrary to the provisions of the act.

161. In the Commission's view, the legislature has determined that a person's rates for use of the transmission system should be postage stamp in nature and should not vary as a result of where that customer is located on the transmission system. For this reason, the DUC proposal must be rejected and the Commission will make no further finding regarding the merits of the DUC's proposal.

5.2.2 Continued use of NCP (billing capacity based regional system charge)

162. The AESO supported the continued use of the NCP demand billing determinant for the collection of regional system demand charges stating that billing capacity reasonably reflects the effect of an individual service on regional transmission system facilities. The AESO explained the regional system is composed of facilities shared by a small number of market participants in a small geographical area. The service of a single market participant can have an effect on the regional system, depending on (i) the nature of the service of the market participant; (ii) the

⁸² 2006 SCC4 (CanLII).

services of other market participants in the area; and (iii) the configuration of the regional system in the area.⁸³

163. Under cross examination by the DUC, the AESO also testified that the power flows on a shared system depend on the power flow of a market participant in conjunction with the power flows of all the other market participants on the same shared system. The net effect on the regional system becomes particularly important when a market participant has both load and generation facilities that may result in power flows either to or from the shared system. The AESO plans the shared transmission system to accommodate both loads on individual system elements as well as overall system operation under peak load conditions. To the extent that individual services are likely to affect loads on individual regional system elements, the billing capacity determinant reflects the capacity of individual services. Based on the foregoing, the AESO submitted that billing capacity is reflective of cost causation and remained an appropriate billing determinant for the regional system charge.

164. In argument, the CCA supported the continued use of the NCP billing determinant. The CCA stated that although the regional system is a network system, it still reflected a greater degree of customer specificity compared with bulk system facilities. Therefore, the CCA submitted billing capacity is an appropriate billing determinant for recovery of regional system costs.

Commission findings

165. The only party to propose an amendment to the manner in which regional charges are billed was the DUC. The DUC proposed a portion of the regional charges be collected on the basis of distance. The Commission has considered and dismissed this proposal in Section 5.2.1 of this decision.

166. The Commission accepts the submissions of the AESO that the use of NCP as the basis for the billing of regional demand charges is reflective of cost causation. The continued use of NCP as the billing determinant for the collection of regional demand charges is approved.

5.3 Point of delivery cost function (POD cost function)

167. In Section 5.3 of the application, the AESO explained its development of the POD cost function and the refinements it had proposed for the tariff. The design of the POD charge in the AESO's demand transmission service (DTS) rate is based on a point of delivery cost function methodology that was established during the AESO's 2007 tariff application proceeding. The POD cost function is developed using an analysis of actual connection project data. The cost function was updated in the AESO's 2010 tariff application, and was updated again in this application.

168. The cost function update included in this application was essentially the same as that proposed in the AESO's 2012 construction contribution policy application filed on June 20, 2012 (Application No. 1067193 and Proceeding No. 1162). In Decision 2012-362, the Commission did not approve the proposed cost function and directed the AESO to refile the cost function in this tariff application. In particular, the Commission expressed concern over the inflation index proposed by the AESO.

⁸³ Transcript, Volume 3, pages 440-441.

169. The AESO proposed two modifications to the inflation index used in previous tariff applications to escalate original project costs to current cost levels. The first modification recognized that the majority of material and construction costs for a connection project are typically incurred by a transmission facility owner (TFO) six to 18 months prior to the in-service date of the project. Original costs for a connection project are, therefore, typically recorded by a TFO one year before a project's in-service date. The AESO escalated all project costs starting from the year before the project's in-service date in the analysis used in its application to reflect this practice. The second modification revised the composite inflation index used by the AESO for the cost function analysis provided as part of its 2010 tariff application and 2011 tariff update. For the 2011 cost function, the AESO used a four-component index based on Statistics Canada indices for substation equipment, transmission line, industrial services, and industrial structures. As Statistics Canada has discontinued the Alberta-specific industrial services index, the AESO had to consider alternative inflation indices.

170. The AESO proposed using an inflation index comparable to that approved by the Commission in Decision 2012-237.⁸⁴ Specifically, the AESO proposed to use a weighted average of the following two Statistics Canada indices:

- for historical equipment cost escalation, the Alberta Consumer Price Index (CPI) from Statistics Canada Table 326-0020, Data Vector V41692327
- for historical labour cost escalation, the Alberta Average Weekly Earnings (AWE) index from Statistics Canada Table 281-0028, Data Vector V1597350

171. The transmission inflation index would be weighted based on 35 per cent of the equipment escalation and 65 per cent of the labour escalation. The 35 per cent equipment and 65 per cent labour weighting reflected a greater labour proportion than the weighting approved in Decision 2012-237, based on results (rounded to the nearest five per cent) of the AESO's analysis of transmission projects in Alberta which were summarized in Table 5-4 of the application.

172. In addition to a revised inflation index, the AESO also proposed refinements to the connection project database. The AESO explained that the point of delivery cost function is based on actual data for connection projects that result from requests by market participants for system access service. Connection projects involve the construction of transmission facilities for the connection of a market participant's facilities to the existing transmission system, and may be either "greenfield" projects or "upgrade" projects. Greenfield projects are those that require the construction of a new substation to provide system access service, while upgrade projects are those that require the construction of additional facilities at an existing substation.

173. The AESO incorporated refinements into the project database. First, the AESO included only projects with cost estimates at the proposal to provide service (PPS) or later stage (with an estimate accuracy of +20 per cent/-10 per cent or better) and where a facilities application has been filed with the Commission. Previously, the database included projects at earlier stages. The AESO considered that limiting projects to those with at least PPS estimates and with facilities

⁸⁴ Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012.

applications filed would reduce the likelihood of future cost and scope changes materially affecting the project data.

174. Second, the AESO used the “maximum DTS capacity” of a connection project in developing the point of delivery cost function in this application. Connection projects frequently have contract capacities that vary over time, usually referred to as “staged” contracts. The AESO considered that the DTS contract capacity associated with a project should reflect the maximum contracted capacity, since that maximum DTS capacity represents the largest capacity that a connection project has been configured and designed to serve.

175. Another major refinement to the database was the inclusion of upgrade project data in this application, based on the same criteria used for including greenfield project data. The AESO considered that the inclusion of upgrade project data improved the point of delivery cost function as it better represented the connection projects that exist in Alberta. The process undertaken for the inclusion of upgrade projects was explained by the AESO at Section 5.3.3 of the application.

176. The AESO stated the challenge in incorporating upgrade projects is that they involve two capacities: the initial capacity that exists before the project and the incremental capacity added during the project. The project cost varies with both the initial capacity (which can be considered the starting point on the cost curve) and the incremental capacity (which can be considered the distance moved along the cost curve). The two capacities interact such that two upgrade projects with the same incremental capacity will have different costs if they have different initial capacities, since the initial capacity determines the starting level at which incremental cost is incurred.

177. To ensure the cost function reflected only the upgrade cost for an upgrade project, the cost of the substation already in place to accommodate the initial capacity (which is considered to have been built as a greenfield project) was calculated using the cost function developed for greenfield projects. The cost of the upgrade project was then added to the calculated greenfield cost to determine a “total” cost for the substation, which would then be capable of serving the total capacity (initial capacity plus incremental capacity) at the substation. An upgrade data point, therefore, reflects the total costs and total capacity at the substation, which would be comparable to the cost and capacity at a greenfield substation, but the total cost would vary from the cost function only to the extent the upgrade cost varied from the cost function.

178. After determining data points for all the upgrade projects, a new power curve regression was analyzed for the composite dataset including all greenfield and upgrade projects. The resulting power curve was slightly different from the original greenfield-only power curve. Since the cost to accommodate the initial capacity at an upgrade project was based on the original power curve, the new power curve changed the data points for upgrade projects slightly. Therefore, the data points for upgrade projects were recalculated based on this first iteration of the power curve, and the new upgrade data points were then used with the greenfield data points to develop another iteration of the power curve. This iterative process was repeated 15 times to allow the power curve determinants to converge on stable values. The AESO considered the iterative process to be appropriate both to develop a stable power curve that is as representative as possible of the combined greenfield and upgrade project data, and to acknowledge that some substations are upgraded multiple times through their lives.

179. In general, the AESO expected that the inclusion of upgrade projects in the analysis would result in an increase in the cost function for projects with larger capacities. Upgrade projects by their nature tend to involve larger contract capacities, since incremental capacity is being added at an existing substation that already has greenfield capacity. The total cost of providing capacity at a substation through initial greenfield construction and later upgrade construction would also typically be higher than the cost of providing the same capacity through one-time greenfield construction. As expected, the cost function increased when upgrade projects were incorporated into its determination, as illustrated in Figure 5-8 of the application.

180. The AESO considered the effect of incorporating upgrade projects into the greenfield cost function to be reasonable. The resulting cost function indicated larger connection projects are generally somewhat more expensive than a greenfield-only analysis would indicate. This is consistent with building sufficient capacity initially for future requirements being more efficient than incremental construction. The AESO considered that including upgrade projects in the development of the cost function appropriately reflects this effect. The final cost function proposed by the AESO is, therefore, based on a combined dataset of 215 connection projects. Some characteristics of those projects are summarized in Table 5-9 of the application.

181. In summary, the development of the cost function in this application differs from the development in the AESO's 2010 tariff application in three aspects: (1) the inclusion of updated greenfield project data; (2) the use of a revised inflation index; and (3) the incorporation of upgrade project data. To illustrate the relative effects of those aspects, Figure 5-11 of the application showed the cost function at each stage of development for this application.

182. Parties raised a number of issues with respect to the AESO's POD cost function proposal. These issues are discussed in the subsections that follow.

5.3.1 Inclusion of greenfield projects with participant owned facilities

183. In its intervenor evidence, the DUC noted that the AESO was excluding from its database analysis certain PODs where customers had paid for and owned part of the facilities. In particular, the DUC referenced upgrade project 715, the Shell AOSP expansion. The DUC noted that the Shell AOSP expansion was excluded from the AESO's project database because substation 402S was customer-owned.

184. The DUC claimed this one project had a material effect on the resulting POD cost function. If this project was added to the greenfield projects, the POD cost function would shift down from the AESO's proposed black line, as shown in Figure 1, to the red line that includes Project 725 as a new greenfield connection.

185. The DUC maintained that the Shell AOSP expansion project was an example where a significant new load (60 MW DTS contract capacity) was connected to the grid for a relatively low cost (\$6.5 million). The DUC stated these types of projects would reduce the slope of the POD Cost function and reflect the economies of scale present for larger customer connections.

186. The DUC noted that there were other greenfield connection projects that have been excluded by the AESO where the substation is customer-owned. Customer-owned substations tend to be associated with larger industrial facilities, often part of an industrial system designation (ISD) that would include on-site generation. For example, the DUC noted there have been several large transmission connections with ISDs that are not included in the AESO's

greenfield project list, including CNRL Horizon 838S and Nexen Long Lake 841S. These, and potentially several other large industrial customers with customer-owned substations, have been added to the system during the AESO's tenure as ISO but remain excluded from the POD cost function analysis. The DUC asserted that these larger connection projects tend to have higher DTS contract capacities and relatively lower connection costs, which would tend to reduce the slope of the POD cost function.

187. Consequently, the DUC recommended that the AESO should be directed to use all greenfield connection projects where the investment policy was applied. Specifically, connection projects where the market participant owns some of the facilities, for example a customer-owned substation, should not be excluded from the connection project database and the development of the POD cost function. Dual use customers pay the same DTS rate as other customers and their projects should not be excluded from the data used to develop the DTS POD rate charges.

188. The AESO opposed the DUC's position. It explained that its project database included only those projects that were load-only and the facilities that were owned by a regulated TFO. Although market participants who own their substation facilities pay Rate DTS, they also receive Rate PSC, Primary Service Credit. The AESO submitted that, as a result of Rate PSC, market participants who own their substation facilities effectively do not pay the same rate as market participants where substation facilities are owned by TFOs, as was suggested by the DUC. Rate PSC is available only to market participants receiving service under Rate DTS and compensates a market participant whose connection does not include conventional transformation facilities owned by a TFO.

189. The AESO explained that it was important to include in the database connection projects that are providing comparable service. Projects with substations owned by TFOs are not comparable to projects with substations owned by market participants.⁸⁵ The AESO also explained that adding the substation costs incurred by market participants could address comparability to some extent, but concerns such as the comparability of standards and comparability of the allocation of distributed costs would remain. In any event, in its response to AESO-DUC-001(a), the AESO noted that the DUC had declared that "the cost of customer owned transmission facilities ... is confidential and commercially sensitive information that cannot and should not be shared with the AESO or made public."⁸⁶

190. The AESO also questioned the value of including costs of customer-owned facilities in the development of the point of delivery cost function even if the substation costs incurred by market participants were to be provided on a basis comparable to the costs incurred by TFOs. The AESO stated the POD cost function is used to determine the rates through which the cost of TFO-owned facilities are recovered and to set investment in facilities owned by the TFO. Bringing in market participant-owned facilities whose costs are not recovered through the POD charges and who do not receive any investment for those facilities may be more comparable to other projects if the AESO had all the information discussed, but the AESO was uncertain it would serve the ultimate goal of establishing rates to recover TFO costs and investment in TFO-owned facilities.⁸⁷

⁸⁵ Transcript, Volume 3, pages 417-418.

⁸⁶ Exhibit No. 217.01, AESO-DUC-001(a).

⁸⁷ Transcript, Volume 3, pages 418-419.

191. Finally, the AESO noted that in its response to AESO-DUC-002(a), the DUC asserted that even though under its proposal the POD cost function would exclude the costs of participant-owned substations, market participants should continue to receive Rate PSC, which also provides a credit to reflect the costs of participant-owned substations. The AESO considered it contradictory and inappropriate to, on the one hand, exclude costs from the cost function and then, on the other hand, provide a credit to reflect those excluded costs.

192. The UCA also opposed the DUC's proposal to include the partial costs of connection projects in the project database. It noted that the DUC had acknowledged the inclusion of the partial costs of connection projects with customer-provided facilities in the project database would pull down the POD cost curve.⁸⁸ Therefore, the UCA submitted that the shape of the POD cost function would be distorted by including the full costs of some projects and the partial costs of other projects.

193. The UCA also noted that in the hypothetical example where all customers over 50 MW provided their own substations, such that the POD cost curve for customers over 50 MW reflected only non-substation costs, the DUC would still recommend that such customers receive a primary service credit. The UCA argued that if the POD charge for customers over 50 MW reflected only non-substation costs, there would be no reason to provide those customers with a primary service credit for customer-provided substations. It further submitted this hypothetical example illustrated why it would be inconsistent to include the partial costs of customer-owned facilities in the project database and also continue to provide a primary service credit to such customers.

194. Further, the UCA noted that the DUC indicated that its members would not be prepared to disclose information on the costs of customer constructed facilities⁸⁹ while the AESO indicated that even if customers provided information on the costs of customer-provided facilities, the AESO would still have concerns regarding the comparability of those costs.⁹⁰ As the AESO did not have access to the costs of customer-owned facilities on a comparable basis, it had properly excluded connection projects with customer-owned facilities from the project database.

195. The CCA stated that while it considered there was merit in the DUC's suggestion, the practical implementation of such an approach may be more challenging. Under such an approach, procedures would need to be developed to ensure all customer-owned substations are included and the costs with respect to such substations reflected the same cost categories as used for TFO substations. If selective inclusion of certain substations was being proposed, then the reason for the selection of certain customer-owned substations and not others would have to be demonstrated and justified. The CCA took no position on this issue and submitted the AESO would be in the best position to assess the costs and benefits of the approach recommended by the DUC.

196. The DUC continued to advocate its position in its argument submissions and responded to the criticisms in its reply argument submissions.

⁸⁸ Transcript, Volume 4, pages 582-583, lines 21-2.

⁸⁹ Transcript, Volume 4, pages 596-597, lines 17-16.

⁹⁰ Transcript, Volume 3, page 417, line 22 to page 418, line 16.

197. In argument, the DUC referred to its response to AUC-DUC-001 where it stated that the connection-related costs for PODs that include TFO-owned transmission facilities that connect to customer-owned transmission facilities (e.g., to ISD assets) are part of the POD related revenue requirement (e.g., a radial line to a customer owned substation) and therefore should be used in the determination of the POD cost function.

198. The DUC found it inconsistent to only include upgrades to a substation (for example, most of the upgrade projects) in the connection project database. Extending the AESO's reasoning, only projects that have costs related to both a substation and a radial line should be included in the connection project database. This would limit the connection project database to greenfield projects, which have been used for the current and prior tariffs.

199. The DUC submitted that if the Commission finds that the inclusion of upgrade projects enhances the accuracy for the POD cost function, through the inclusion of projects where market participants are appropriately responding to the AESO's tariff, then the Commission should also find that projects that include a connection to a customer owned facility should also be included in the connection project database.

200. The DUC further submitted that there is no material distinction between the proposed upgrade projects and projects that connect to a customer-owned facility. While upgrade projects tend to be smaller, projects that connect to customer-owned facilities tend to be larger. Including the former and excluding the latter inappropriately increases the slope of the POD cost function. The DUC argued that the Commission should find that either all projects should be included in the project connection database, or only the greenfield projects.

201. The DUC responded to the AESO's position that inclusion of greenfield projects with customer-owned facilities would be contradictory and inappropriate with providing the primary service credit (PSC) by arguing that the inclusion of greenfield projects with customer-owned facilities will likely reduce the slope of the POD cost function, resulting in lower POD charges. If the inclusion of greenfield projects with customer-owned facilities results in even a 10 per cent reduction in some of the POD charges, this does not justify removing the 79 per cent reduction provided due to customers building, owning and operating their own substations. The DUC submitted that the AESO is mixing two different concepts. The POD cost function is intended to provide an estimate of the capital cost to connect a new customer. Customers with ISDs and customer-owned facilities are part of the mix of connecting customers and the actual connection costs should be included in the connection project database. The PSC is a rate design that reflects that the AESO's revenue requirement does not include costs associated with customer-owned facilities. Linking these two different concepts to justify excluding greenfield projects with customer-owned facilities is contradictory and inappropriate.

202. In reply argument, the AESO argued that comparability of projects used for the point of delivery cost function has been an important aspect of the cost function since its use was first approved in Decision 2007-106 and that comparability and consistency of projects remain important for the development of the point of delivery cost function. Including projects with customer-owned facilities as recommended by the DUC would include projects in the cost function dataset that were not comparable. Inclusion of these projects could be expected to decrease the accuracy and robustness of the relationship between DTS capacity and complete point of delivery costs represented by the cost function.

203. The AESO also noted that the DUC suggested that upgrade projects should be excluded because they are not comparable to greenfield projects.⁹¹ The AESO submitted that a connection project that was initially constructed as a lower-capacity greenfield project and later upgraded to a higher DTS capacity was, in fact, comparable to a connection project that was constructed as a single project to the higher capacity. Both projects would serve the same DTS capacity and would include similar substation and radial line facilities, although one would be constructed in two stages while the other would be constructed in a single stage. The AESO submitted that including upgrade projects in the cost function dataset was comparable to including greenfield projects, increased the number of projects in the dataset and, accordingly, resulted in a point of delivery cost function that was more representative of connection projects on the transmission system.

Commission findings

204. The DUC has argued for the inclusion in the database of all greenfield projects, including those with customer-owned facilities, on the basis that the exclusion of these types of projects would have a material effect on the slope of the POD cost function. In particular, the slope of this function would be smaller for every level of project size if these projects were to be included in the database.

205. The AESO explained that its project database included only those projects that were load-only and the facilities that were owned by a regulated TFO. The AESO also explained that it was important to include in the database connection projects that are providing comparable service and projects with substations owned by TFOs were not comparable to projects with substations owned by customers and that comparability and consistency of projects remains important for the development of the point of delivery cost function.⁹²

206. The database is used by the AESO to determine total POD costs, demonstrate the correlation between capacity and cost at a given POD and to collect POD costs from customers in an equitable manner. The Commission considers it unreasonable to include projects in the database but not the total cost of constructing the project. In the Commission's view, including projects but not the full cost for all projects creates an apples to oranges comparison between projects and introduces an element of distortion into the POD cost function and database that is not justified.

207. Further, in its response to AESO-DUC-001(a), the DUC had declared that "the cost of customer owned transmission facilities ... is confidential and commercially sensitive information that cannot and should not be shared with the AESO or made public."⁹³ The costs of projects that are currently included in the database are publicly tested and these project costs are ultimately approved by the Commission if they are determined to be prudently incurred. Further, the TFO must meet particular specifications for these substations as directed by the AESO. No such scrutiny occurs with regard to customer-owned substations. The customer has complete discretion to spend whatever the customer considers necessary to meet its needs and to develop whatever design it chooses to meet its needs so long as it can safely connect to the transmission grid. The DUC has argued that the inclusion of these costs in the database would reduce the

⁹¹ Exhibit No. 362.01, DUC argument, page 22, lines 31-34.

⁹² Transcript, Volume 3, pages 417-418.

⁹³ Exhibit No. 217.01, AESO-DUC-001(a).

slope of the POD cost function and reflect the economies of scale present for larger customer connections. This assumes that the costs incurred by these customers will always be lower than the costs incurred by substations owned by TFOs. However, quite apart from the issue of comparing like costs to like costs, there is no way to determine whether these costs are prudent. It is reasonable to assume that a customer would want to keep its costs as low as possible. However, if the substation is only one cost element of its project and spending more than the lowest cost to meet its overall project objective is required, it is also reasonable to assume that the most rational choice for the customer would be to incur this additional cost. Given the customer's insistence on maintaining the confidentiality of its costs, there is no way for the Commission to evaluate the effect of the inclusion of customer-owned substation costs in the database.

208. The proposal of the DUC is denied. The AESO is directed to continue to exclude customer-owned projects from the database and POD cost calculations.

5.3.2 Inflation factor

209. In its past tariff applications, the AESO used an inflation index to escalate original project costs to current cost levels. The AESO proposed two modifications to this past inflation index in Section 5.3.2 of the application.

210. The first proposed modification was intended to recognize that the majority of material and construction costs for a connection project were typically incurred by a transmission facility owner six to 18 months prior to the in-service date of the project. Original costs for a connection project were, therefore, typically recorded by a transmission facility owner one year before a project's in-service date. The AESO therefore escalated all project costs starting from the year before the project's in-service date in the analysis used for the application. (The year before the in-service date was indicated as "ISD-1" in the project database.)

211. The second modification revised the composite inflation index used by the AESO for the cost function analysis provided as part of its 2010 tariff application and 2011 tariff update. For the 2011 cost function, the AESO used a four-component index based on Statistics Canada indices for substation equipment, transmission line, industrial services, and industrial structures but Statistics Canada discontinued the Alberta-specific industrial services index. Therefore, the AESO had to consider alternative inflation indices.

212. The AESO stated that it initially reviewed inflation indices used by transmission facility owners in Alberta. However, after consideration of the comments by the Commission in Decision 2012-362, AESO 2012 Construction Contribution Policy, the AESO implemented an inflation index comparable to that approved by the Commission in Decision 2012-237, Rate Regulation Initiative, Distribution Performance-Based Regulation.

213. Specifically, the AESO proposed to use a weighted average of the following two Statistics Canada indices:

- for historical equipment cost escalation, the Alberta Consumer Price Index (CPI) from Statistics Canada Table 326-0020, Data Vector V41692327
- for historical labour cost escalation, the Alberta Average Weekly Earnings (AWE) index from Statistics Canada Table 281-0028, Data Vector V1597350

214. The AESO explained that for forecast escalation, the AESO proposed to use comparable forecasts of the Alberta consumer price index and Alberta average weekly wages in long-term economic outlooks from the Conference Board of Canada.

215. The AESO further explained that the transmission inflation index would be weighted based on 35 per cent of the equipment escalation and 65 per cent of the labour escalation. The 35 per cent equipment and 65 per cent labour weighting reflected a greater labour proportion than the weighting approved in Decision 2012-237 for distribution system owners, based on results (rounded to the nearest five per cent) of the AESO's analysis of transmission projects in Alberta summarized in Table 5-4 of the application.

216. The AESO asserted that the proposed two-component index had additional advantages of being simpler than the previous four-component index and being based on widely-used Statistics Canada indices that were not expected to be discontinued in the foreseeable future.

217. Some parties have made inflation related comments in their arguments with respect to customer contribution policy and investment levels. Some of those arguments have been presented in this section. In particular, the Commission notes that Devon, in its evidence relating to investment, has proposed a fundamentally different approach that would use a five-year rolling average of project costs without any inflation factor, in contrast to the AESO proposal to use the full project database for determining the POD cost function and related investment levels. While some of Devon's comments with respect to inflation are dealt with in this section, the details of the Devon proposal are dealt with elsewhere in the decision.

218. In its intervenor evidence, Devon noted the AESO had stated that actual costs of investment were increasing at a rate of 13 per cent/year⁹⁴ while the inflation index proposed by the AESO only averaged 3.36 per cent. Devon suggested the price signal resulting from such mismatches would not be economically efficient, nor would it be properly reflective of cost causation, violating key policy principles and proposed a different approach, a rolling five-year average, that would not require inflation adjustments.

219. Devon explained that the issue with inflation was highlighted in the AESO's response to Access-AESO-001. In the revised cost spreadsheet provided in response to this information request, the AESO highlighted 16 Greenfield projects where costs had been changed. Final costs are determined for these projects up to six months after construction and energization. While the AESO's 2012 contribution policy application used PPS level costs, several projects now had final costs. Devon found it interesting that over the course of little more than a year, most of the projects in the AESO's update had a significant increase. Devon provided a table⁹⁵ that showed that the nominal costs of these projects, on average, increased by 12 per cent, well above the inflation adjustment of approximately three per cent.

220. In its argument, the CCA supported the AESO's adjusted inflation index, stating that the proposed approach simplified the inflation index determination.

221. In its argument, AltaLink asserted that by using the proposed inflation factor and including projects in the database that were not representative of the service characteristics,

⁹⁴ Exhibit No. 109.01, AUC-AESO-21(a).

⁹⁵ Exhibit No. 146.02, Depal evidence on behalf of Devon, Table A, page 11.

functionality and standards of current projects, the proposed customer contribution policy virtually ensured that the investment formula would not achieve a 60 per cent investment level on actual projects to be covered by the tariff. Neither did this achieve the principle of intergenerational equity. AltaLink proposed that the AESO be directed to reconstitute the 2012 customer contribution policy working group to address the Commission's specific concerns outlined in Decision 2012-362.⁹⁶ In the interim, AltaLink recognized the need for a contribution policy and recommended the approach outlined in the Devon evidence since that approach would achieve a reasonable investment level.

222. AltaLink further noted that in Decision 2012-362, the Commission observed that it did not think the principle of intergenerational equity, which it found to have been elevated by the AESO relative to the more important policy objective of providing an efficient price signal, would be sacrificed at a 60 per cent investment level. AltaLink suggested that any formula accepted by the Commission should at least achieve this level of investment when applied to actual projects covered by the tariff. AltaLink submitted that proposing a formula that was intended to achieve investment coverage of 60 per cent over all projects in the database, while disregarding the results of the formula as it applied to more recent and actual projects, ignored the reality and true costs of connecting loads to the transmission system.

223. In particular, AltaLink submitted that in response to AML-AESO-002(b), the AESO confirmed that if its proposed investment formula were applied to more recent projects with an in-service date of 2010 or later, the formula would achieve an investment level of only 48 per cent over those projects.⁹⁷ When the formula was applied to more recent projects with higher costs, the result was significantly diminished and a true investment level of 60 per cent on actual projects was not achieved.

224. The UCA addressed Devon's proposal in its argument submission. It stated that there were many reasons why projects constructed during any particular five-year period may have higher than average project costs in comparison to the entire project database. As noted in the response to AUC-AESO-021(a), factors that can contribute to higher than average project costs include geographic location; building in advance of bulk system expansion; delays in regulatory approvals or other unforeseen circumstances; recently-implemented requirements for participant involvement and additional consultation; and unexpected requirements to outsource construction.⁹⁸ In the response to AUC-AESO-21(a), average project costs have increased by about 13 per cent per year, well above the average rate of inflation. The UCA submitted this was strong evidence that factors other than inflation have contributed to the recent increases in project costs. and noted that even Devon acknowledged that geographic location can influence costs due to the prevalence of muskeg in some regions and the resulting requirement for winter-only construction; environmental restrictions such as caribou zones; and higher labour costs in some regions than others.⁹⁹ The UCA rejected Devon's proposal and submitted that the entire project database should be used for the investment function.

225. In its argument, the AESO also referenced its response to AUC-AESO-021. The AESO stated some of those factors would be captured by the proposed inflation index, which primarily

⁹⁶ Exhibit No. 359.02, AltaLink argument, paragraph 7.

⁹⁷ Exhibit No. 110.01, AML-AESO-002(b).

⁹⁸ Transcript, Volume 2, pages 211-213, lines 1-3.

⁹⁹ Transcript, Volume 6, pages 934- 936, lines 12-17.

reflected input cost changes. With respect to the other factors, the AESO noted that, under cross examination by AltaLink, it stated the other factors:

may be relatively short-term changes. They occur at a particular period in time and then don't result in further increases beyond that So it looks like some of the factors that may have resulted in large increases in the recent past may have stabilized or not be something that would result in even greater increases in the future.¹⁰⁰

226. The AESO submitted that the effect of these non-input cost factors would be captured by periodic updates to the project cost database as part of the comprehensive tariff applications filed by the AESO.

227. In response to the AESO's assertion that its proposed inflation index was practical and appropriate for escalating connection project costs, the DUC expressed its disagreement and noted that in argument, IPCAA implicitly criticized the adequacy of the inflation index in its comments about the appropriateness of the POD cost function.¹⁰¹ The DUC submitted that the Commission should direct the AESO to continue to refine the inflation index to reflect actual cost increases experienced over time in Alberta.

228. In its reply argument, Devon stated that factors other than those captured by narrow inflation indices have been and will no doubt continue to have an effect on transmission project costs. Further, none of the guiding principles agreed to by stakeholders and the Commission supported the exclusion of selected cost drivers because they did not match an arbitrary inflation index.

229. Devon also stated that connection projects were unique and the high level of cost increase reflected the actual inflation experienced by ratepayers in Alberta for new connections. Arbitrarily determining what part of the cost increase was due to "inflation" and what was due to something else and using this to justify a low level of increase in investment levels did not make sense in Devon's view.

Commission findings

230. Devon has proposed a fundamentally different approach for the Commission to consider from that advanced by the AESO. The approach proposed by Devon relies on an ongoing re-determination of investment coverage which is dependent on a short term five-year rolling project database rather than a long-term dataset in which the original cost of connection projects is brought to a common value with current projects through the use of an inflation index.

231. The purpose of the investment function is to provide a price signal to customers when they are making decisions that result in high cost connections. Customers who choose to connect at a point in time or in a location where costs are higher than the average POD cost will not receive the benefit of the maximum allowed level of investment coverage for a POD. Conversely, customers who locate in lower cost areas and receive the benefit of the maximum allowed level of investment coverage for a POD, may benefit from a coverage ratio that is higher than the average investment coverage ratio of 60 per cent. Notwithstanding, all customers,

¹⁰⁰ Transcript, Volume 2, pages 211-212.

¹⁰¹ Exhibit No. 403.01, DUC reply argument, page 14, lines 2-3.

regardless of choice, will pay the same rates for the same level of service and relative amount of system investment.

232. Only a few customers receive exactly the benefit of the average level of investment. The use of an average inflation rate representative of cost increases that would be faced by all projects over time is just that, an average. It will result in POD cost rates and investment levels that are reasonable and representative of all projects constructed in all regions over time.

233. As the UCA has noted and Devon has acknowledged, location can influence cost due to, for example, the prevalence of muskeg in some regions and the resulting requirement for winter-only construction. The Commission does not consider the variation in coverage ratios and investment levels for such projects due to the use of an inclusive average inflation rate to be unduly preferential or unjustly discriminatory.

234. In consideration of the foregoing, the Commission rejects the position that the adequacy of investment coverage can be used as an argument that the inflation index employed to escalate the historic cost of connection projects to current year values is unreasonable.

235. Having regard for the above, the Commission notes that the AESO proposed a new inflation index as a result of the fact that Statistics Canada has discontinued the previously used index. Apart from questioning the underlying validity of the approach of using an inflation index to facilitate the consideration of prior year projects in the assessment of investment coverage, no other party proposed an alternative index, or provided arguments as to why the new index proposed by the AESO should not be accepted. The Commission considers the new index proposed by the AESO to be reasonable for both this purpose and for use in the update of the investment function that will be completed in conjunction with annual tariff updates. The AESO's proposed inflation index is approved as filed.

5.3.3 Exclusion of upgrade projects where capacity increase not accounted for

236. In its intervenor evidence, the DUC raised a concern with the fact that, while the AESO has included the full construction cost of the upgrade project, it has not accounted for the full increased capacity associated with the upgrades. The DUC noted that there were 10 upgrade projects where there was no DTS contract capacity increase, even though over \$35 million was expended on these projects. As noted in Figure 5-7 of the AESO application, upgrade projects increase the level of the POD Cost Function; however, adding upgrade projects with no capacity increase exacerbates this result and tends to increase the slope of the POD cost function.¹⁰²

237. The DUC noted that the AESO justified its position by stating zero MW upgrade projects should be included in the development of the cost function because they represent actual costs incurred to provide system access service and that zero MW upgrade projects reflect market participant response to the price signals in the ISO tariff.¹⁰³

238. The DUC's concern with the AESO's premise was that not all AESO customers may be fully contracting for the upgrade capacity they are requesting. A DFO does not have the same financial incentive as an AESO direct connect customer to rationalize its DTS contract capacity.

¹⁰² Exhibit No. 143.01, DUC evidence, Figure 2, page 11.

¹⁰³ Exhibit No. 111.01, IPCAA-AESO-004(b).

The DUC maintained that an AESO direct connect customer has the financial incentive to request a DTS contract capacity at about 90 per cent of the expected peak measured demand. Under the DTS rate, contracting for less than 90 per cent of billing demand does not affect the monthly DTS rate charges, but does result in lower investment.¹⁰⁴ Therefore, a rational AESO customer would maximize the DTS contract capacity to receive the maximum investment, but only up to a point where the DTS rate charges are not affected. For a DFO, however, DTS rate charges are a flow-through to its customers and, therefore, the same level of discipline in selecting a higher DTS contract capacity may not exist. Further, any capital contribution paid by a DFO is treated as a capital investment that will increase rate base and earnings. Consequently, DFOs may have the incentive to elect a lower DTS contract capacity when requesting a transmission upgrade.¹⁰⁵

239. In response to DUC-AESO-001(e), the AESO advised that “Market participants, including distribution system owners, request new contract capacity or increases to contract capacity through a system access service request” and that “the AESO does not review system access services to assess the reasonableness of ongoing contract capacities.”¹⁰⁶ The DUC argued that based on this response, DFOs can request that capital be expended for an upgrade without having to contract for the additional capacity the upgrade provides.

240. Further, in DUC-AESO-001(f), the DUC asked the AESO to provide average 2012 DTS billing capacity in MW for each upgrade project. When compared to the DTS contract capacity at some PODs, where an upgrade occurred and the DTS contract capacity was not increased, the average DTS billing capacity was, on average, 35 per cent higher and in one case, up to 300 per cent higher.¹⁰⁷ This response supported its position that DFOs are requesting upgrades, such as larger transformers, and are not requesting higher DTS contract capacities, even though the load at the POD has or should have increased with the upgrade.

241. The DUC recommended that if upgrade projects are to be included in the AESO’s connection project database used to develop the POD cost function, then the additional capacity that results from the upgrade should be used, instead of the DTS contract capacity increase. If the AESO cannot reasonably determine the increased capacity for these upgrades, then in the alternative, the DFO-requested upgrade project should be excluded from the connection project database. The DUC submitted that dual use and other AESO direct connect customers should not be disadvantaged with higher DTS rates resulting from the DFOs not contracting for the increased capacity distribution customers need and pay for through the distribution rates.

242. The AESO rejected the DUC’s recommendation and noted that during cross examination, it explained there was no valid reason to exclude an upgrade project when a market participant is responding to the price signals in the ISO tariff, stating:

¹⁰⁴ The Commission notes DUC is referring to the point of delivery charge component of the DTS Rate which can be found at page 3 of Appendix L to the application. The terms billing capacity, contract capacity and metered demand are used in the DTS rate and are defined at pages 1, 2 and 5 respectively of Appendix M to the application.

¹⁰⁵ Exhibit No. 143.01, DUC evidence, Q. 15, page 11 of 34.

¹⁰⁶ Exhibit No. 115.01, DUC-AESO-001(e).

¹⁰⁷ Exhibit No. 143.01, DUC evidence, Table 1, page 12, information extracted from Exhibit No. 115.06, Attachment DUC-AESO-001(f).

One of the things we found is that market participants contract at different levels for different reasons, and it varies from market participant to market participant. Most market participants contract close to their operating load and maintain that over time. When there's a change at a project, though, such as one of the upgrade projects or even some of the greenfield projects, the market participant might not, initially, contract for additional capacity. There may be uncertainty about exactly what the requirements will be going forward and a contract is a multiyear commitment. They might not be willing to take on that multiyear commitment. Market participants can sometimes find it easier to pay a construction contribution than actually enter into a long-term agreement for future payments because they treat capital costs differently than operating costs. It may be that they previously had contracted for a higher capacity, which they intend to maintain for the future, and the upgrade project is providing additional reliability, perhaps, or additional flexibility in connecting to additional feeders from the substation. So there can be many reasons for a market participant not increasing contract capacity for an upgrade project

[T]he fact that the market participant didn't at this time increase their contract capacity by what we expected or what we might expect didn't seem a valid reason to exclude them.¹⁰⁸

243. The AESO submitted the POD cost function is appropriately based on contract capacity increases for upgrade projects. The contract capacity increase determines both (i) the amount of investment for which an upgrade project is eligible; and (ii) becomes a component of the billing capacity on which monthly point of delivery charges are based in Rate DTS. In contrast, neither the amount of investment nor billing capacity is based on the additional physical capacity that results from an upgrade project. The AESO explained the tariff and the inter-relationship of maximum investment levels and Rate DTS point of delivery charges, ensures reasonable recovery of investment. Further, the AESO would determine if a construction contribution adjustment was required when a market participant requested a change in contract capacity at an existing system access service.

244. The AESO submitted there was no evidence on the record in this proceeding that the price signals provided by the ISO tariff are not equally effective for both direct connect market participants and DFOs. The Commission and its predecessors have previously considered the applicability of the ISO tariff to direct connect market participants and DFOs, and have consistently concluded that the ISO tariff should apply equally to both.¹⁰⁹

245. In summary, the AESO submitted that upgrade projects with zero MW or small capacity increases should be included in the connection project database for determining the point of delivery cost function because such projects:

- (a) represent actual costs incurred to provide system access service;
- (b) reflect market participants' responses to the price signals in the ISO tariff;
- (c) reflect the different reasons market participants may not increase capacity, none of which are valid for excluding an upgrade project from the database; and
- (d) result in effects on maximum investment levels and Rate DTS point of delivery charges based on those contract capacity increases.

¹⁰⁸ Transcript, Volume 3, pages 420-422.

¹⁰⁹ Decision 2007-106, page 103.

246. The UCA opposed DUC's proposal to exclude upgrade projects with no capacity increases. The UCA argued that if a customer requests an upgrade and does not increase its contract capacity, then the customer makes a full contribution to the cost of the upgrade. The UCA also accepted the AESO's position that there may be legitimate reasons for a customer to request an upgrade without committing to an increase in contract capacity.¹¹⁰ The UCA also agreed with the AESO that simply because a customer is prepared to make a full contribution to the cost of an upgrade project, is not a valid reason to exclude that upgrade project from the POD database.

247. In its argument submission, the DUC clarified that it did not oppose the inclusion of upgrade projects in the project database. Rather, the DUC objected to how the AESO proposed to represent the upgrade projects. The DUC noted that the AESO had stated upgrade projects are, on average, more expensive than greenfield projects since a "retrofit" is more expensive than "new construction." The DUC did not accept this premise. Upgrading a transformer, for example, should be more cost effective than building a new substation. The fundamental problem with the method in which the AESO was adding the upgrade projects was the inclusion of all the costs, without allowing for a proper inclusion of the incremental capacity. The DUC maintained that adding incremental costs without accounting for the incremental capacity simply results in the POD cost function representing higher cost connections than may be appropriate.

248. As an example, the DUC referenced its discussion of Upgrade Project 589 with the AESO in its cross examination of the AESO witnesses.¹¹¹ Under this project, fans were added to existing transformers to increase the capacity by either five or 10 MVA (about 4.5 or nine MW). The cost of the upgrade was \$23,000 in 2006 and, therefore, for a relatively small cost, this POD had a material increase in capacity. At the time of the upgrade in 2006, the City of Red Deer elected not to increase its DTS contract capacity, which remained at 37 MW. It was not until 2010 that the City of Red Deer elected to increase the DTS contract capacity from 37 MW to 44 MW. Therefore, the DUC submitted that for Project 589, the connection project database should reflect an upgrade project with a seven MW DTS contract capacity increase from 37 MW at an adjusted 2014 cost of \$31,309.

249. The DUC maintained that if a capacity increase is provided, the resulting POD cost function should represent lower connection costs. This is appropriate as some projects, like Upgrade Project 589, can provide for a significant capacity increase (e.g. seven MW) for a very low cost (e.g., \$31,309). For Upgrade Project 589, the cost of the upgrade was about \$3,500/MW. The DUC also noted that on average, all of the upgrade projects are about 50 per cent cheaper on a per MW basis than the greenfield projects.¹¹² Consequently, adding the upgrade projects should result in lower connection costs, not higher.

250. Additionally, in its response to AESO-DUC-004, the DUC demonstrated that the exclusion of the upgrade projects with under five MW in incremental DTS contract capacity did not materially change the POD cost function.¹¹³ The DUC submitted that this evidence clearly shows that it is the upgrade projects that have not been appropriately allocated a reasonable capacity increase that are causing the increase in the slope of the POD cost function. Further, in

¹¹⁰ Transcript, Volume 1, page 114, line 6 to page 116, line 5.

¹¹¹ Exhibit No. 273.01, DUC cross aids panel, Upgrade Project 589 details.

¹¹² Transcript, Volume 1, page 108, lines 18-22.

¹¹³ Exhibit No. 217.01, AESO-DUC-004, page 9.

the same IR response, the DUC provided evidence to show that the inclusion of the upgrade projects with under five MW of DTS contract capacity increase resulted in higher DTS POD charges for PODs with billing capacities above 20 MW. The DUC submitted that the inclusion of these upgrade projects, as proposed by the AESO, was not appropriate and did not reflect cost causation.

251. The DUC argued that the AESO has not utilized the full DTS capacity of each POD as suggested by the Commission in Decision 2007-106. The DUC maintained using the current or maximum DTS contract capacity for the greenfield projects is doubly important since the upgrade projects all use a base cost derived from the greenfield projects. If the current or maximum DTS contract capacity is utilized for each project, a more accurate POD cost function, that better reflects cost causation, will result. The DUC recommended that the Commission direct the AESO to revise its connection project database accordingly.

252. In response to the UCA's position, which supported the AESO's approach, the DUC argued that the UCA failed to note that the full cost of the upgrade, including both allowed investment and capital contribution, is used in the connection project database. At issue is not the inclusion of the full cost of the upgrade, but the correlation of the appropriate capacity addition to the full connection cost. At a minimum, the connection project database should reflect the current maximum DTS contract capacity at each POD, not the DTS contract capacity that was elected when the POD was constructed or upgraded.

253. In their argument, the CCA considered that the DUC recommendation, to the extent it was material, would result in a more realistic POD cost function and investment levels. Accordingly, the CCA recommended that the DUC recommendation be accepted.

254. In reply argument, the AESO acknowledged that the maximum DTS capacity for Project 589 should be identified correctly as 44 MW in the connection project database. However, the AESO submitted that this represented the identification of an error in the data rather than a flaw with the use of maximum DTS capacity as has been proposed by the AESO.

255. The AESO also noted that the DUC had identified differences between contract capacities in the POD cost function workbook provided as Appendix G of the application and the substation information provided in response to technical meeting question TMQ-001. The AESO submitted that these differences are primarily inadvertent effects of using data retrieved from the AESO's records at different times. The AESO maintained that differences between similar data retrieved at different times are to be expected, and do not indicate any fundamental flaw with the approach or methodology proposed by the AESO. The AESO submitted that the use of maximum DTS capacity for the connection project database should be approved as proposed by the AESO.

Commission findings

256. The DUC is concerned that the AESO is including upgrade projects in the database, along with the cost of the upgrade, but not properly accounting for the full additional capacity created by the expenditure on the upgrade. In particular, the DUC asserts that upgrade projects tend to increase the POD cost function and adding projects, without including the additional capacity created from those projects, exacerbates this problem, increasing the slope of the POD cost function.

257. The AESO rejected the concerns of the DUC. The AESO maintained the POD cost function is appropriately based on contract capacity increases for upgrade projects. The contract capacity increase both determines (i) the amount of investment for which an upgrade project is eligible; and (ii) becomes a component of the billing capacity on which monthly point of delivery charges are based in Rate DTS. In contrast, neither the amount of investment nor billing capacity is based on the additional physical capacity that results from an upgrade project. The inter-relationship of maximum investment levels and Rate DTS point of delivery charges, ensures reasonable recovery of investment. In testimony Mr. Martin stated:

We found that market participants make choices around contract capacity for various reasons. Sometimes they are less certain about what's going to go on in the future and don't wish to commit to a long-term contract at any particular point. Sometimes the opposite happens, and they wish to ensure capacity is available in the future and will commit significantly more than their current load. Sometimes they will stage things over time. And all of those represent reasonable responses by market participants to the AESO's tariff and contribution policy. So we think all those points should be considered in developing the rates and investment levels for the tariff.¹¹⁴

258. The Commission agrees with the DUC on these matters. In the Commission's view, a central purpose of the POD project database is to determine the correlation between cost and capacity and to ensure this is appropriately reflected in the POD cost function and the slope of the cost curve. The AESO's practice of using total project costs but only contracted capacity introduces an element of distortion because it does not match the actual capacity created by the actual expenditure of funds.

259. The Commission notes the AESO's comments that customers may have reasons for contracting at a lower level of capacity than that built into the substation; however, the Commission considers that matching costs to capacity will result in a more accurate price signal and achieve a cost allocation that is reflective of cost causation.

260. The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database.

5.3.4 Determination of customer fixed portion

261. In its evidence, the DUC noted that the AESO had utilized a 0.1 MW low end point in the determination of the fixed portion of the POD cost function. The DUC maintained that this data point did not represent how costs were actually incurred for new connections. Additionally, the use of the 0.1 MW low end point would result in many customers receiving significant rate reductions.

262. The DUC noted that under the AESO's proposed rate design, the low end data point sets the customer fixed value, a value that is analogous to a connection with no DTS contract capacity or the cost of building a minimum capacity POD. Since 2007, the customer fixed value has been between \$800,000 and \$900,000. For the 2014 tariff, the AESO is proposing that the customer fixed value be reduced by 43 per cent to \$550,000. The DUC asserted that reducing the

¹¹⁴ Transcript, Volume 1, pages 114-115.

customer fixed value was nonsensical in light of the increasing costs of building substations and that the fixed value should be increasing due to cost escalation.

263. The DUC referenced Decision 2007-106, in which the Commission directed the AESO to use the lowest valued DTS contract capacity in the connection projects database, which should result in the low end data point at 1.5 MW.¹¹⁵ Accordingly, the DUC recommended that the low end data point be set at 1.5 MW, instead of 0.1 MW, consistent with Decision 2007-106.

264. Additionally, the DUC noted that the lowest DTS contract capacity amongst the greenfield projects was 6.0 MW.¹¹⁶ For a new connection under 10 to 20 MW, the DFOs would try to provide service from the distribution system if economically feasible. The DUC submitted that a 1.5 MW low end data point was conservative and would provide for POD charges that are more consistent with prior tariffs.

265. The DUC explained that the low end data point affected the POD cost classification, which, in turn, was used to determine the DTS POD charges. Using the AESO's proposed low end point of 0.1 MW yielded a \$0.549 million customer fixed amount while the use of a 1.5 MW point yielded a \$1.846 million customer fixed amount.¹¹⁷ The DUC submitted that the continued use of the 0.1 MW data point causes an unwarranted shift in the POD classification that would unnecessarily affect customers with smaller PODs. In addition, the DUC stated that the use of the 1.5 MW low point would lead to a higher customer fixed charge of \$8,859/month, which was more in line with prior rates,¹¹⁸ while using the 0.1 MW low end point yielded a monthly fixed charge of \$2,670/month.

266. With respect to the effect of a lower customer fixed cost on end use rates, the DUC explained that a lower customer fixed charge, as proposed by the AESO, resulted in AESO customers with a lower DTS billing capacity receiving a significant rate reduction. The AESO's rate effect shows that 151 customers would receive a rate reduction of zero per cent to 10 per cent, and 48 customers would receive rate reductions over 10 per cent, when the cost of electricity (commodity) is included.¹¹⁹ A large number of those customers who would receive a rate reduction are small PODs with proposed lower DTS POD charges resulting from the 0.1 MW low end data point. In contrast, a higher customer fixed charge and lower $\leq (7.5 \times \text{SF})$ MW demand block charge, as proposed by the DUC, results in only 45 customers receiving a rate reduction of zero per cent to 10 per cent, and 25 customers with over 10 per cent rate reductions, when the cost of electricity (commodity) is included.¹²⁰ The distribution of customers with rate reductions is significantly reduced with 77 per cent of customers receiving a rate increase of zero to 10 per cent.

267. In its argument, the AESO acknowledged the concerns of the DUC and referred to their comments under cross examination to justify the rate reductions for small capacity services:

So I think if nothing else was changing in the application, it would be reasonable to expect that the cost for the .1 or zero megawatt customer would increase as well.

¹¹⁵ Exhibit No. 9, Appendix G, POD Cost Function, tab Pre-AESO Projects, cell H9.

¹¹⁶ Exhibit No. 9, Appendix G, POD Cost Function, tab Greenfield Projects, cell X41.

¹¹⁷ Exhibit No. 143.01, DUC evidence, pages 17-18.

¹¹⁸ Exhibit No. 143.01, DUC evidence, page 18.

¹¹⁹ Exhibit No. 143.01, DUC evidence, page 20.

¹²⁰ Exhibit No. 143.01, DUC evidence, page 21.

One of the big changes that is happening in this application, though, is that we're implementing the results of a new cost causation study. The prior study had transmission costs allocated roughly 40 percent to bulk system, 20 percent to regional system, 40 percent to point of delivery.

The results in this latest cost causation study shifts that significantly to about 60 percent to the bulk system, 20 percent to the regional system, and 20 percent to the point of delivery.

So proportionally, point of delivery costs are decreasing by 50 percent. So all else being equal, you would expect point of delivery cost to go down. So that's one part.

The other part is that we have revised the point of delivery cost function such that its shape is modified, and the modification of that shape, regardless of which end point was chosen provided the end point remained constant, would result in an impact.¹²¹

268. The AESO disagreed with the DUC's statement that the use of the 1.5 MW end point would result in fewer customers receiving rate reductions and that this was more consistent with past and present rate designs stating:

Very few market participants have zero megawatts of capacity. They typically contract for at least 5 megawatts of capacity, more frequently 7 and a half and higher

The very small customers that are highlighted in DUC's evidence are typically either load services serving generation, which has very little reflection of the actual cost of facilities connecting those customers, or the service they're receiving, or isolated communities.

So neither of those should be looked at as typical services, and I don't think it's reasonable to say that the way we charged them under the prior cost function was the right way we should have charged them.

Because those services are not typical, it's difficult to assess whether the cost function is charging them an appropriate amount or not, so who's to say which cost function is the correct one?¹²²

269. In response to the DUC's claim that moving the 0.1 MW data point to 1.5 MW increases the number of services receiving an average rate increase of zero per cent to 10 per cent, the AESO submitted that trying to provide the same bill effect to most services assumed that the previous cost function was superior to the proposed one and should effectively be retained. The AESO stated because of the atypical nature of small services, it was not possible to determine which cost function was "correct." Nevertheless, the AESO submitted that the evidence provided at paragraphs 172 to 221 of the application demonstrated that the proposed cost function was significantly improved over previous cost functions.

270. In its argument, the DUC reiterated the concerns expressed in its evidence.¹²³ The DUC noted that under cross examination, the AESO admitted that the use of a 0.1 MW low end data

¹²¹ Transcript, Volume 3, pages 423-424.

¹²² Transcript, Volume 3, pages 424-425.

point would provide rate reductions of over 30 per cent to the smallest PODs, some of which are isolated generation PODs that have extremely low revenue to cost ratios.

271. The CCA agreed with the position of the DUC. The CCA stated that using a notional lowest point for the POD cost function of 0.1 as proposed by the AESO was not reflective of the reality of the minimum size POD.¹²⁴ Accordingly, the CCA recommended that the 1.5 MW minimum point proposed by the DUC be accepted.

272. The UCA opposed the DUC's proposal to change the low end point used for POD cost classification and agreed with the AESO that the updated POD cost function is a significant improvement over the previous POD cost function.¹²⁵ The UCA submitted that the reduction in the monthly fixed charge was not relevant, since there are virtually no customers with zero MW of capacity. The UCA also submitted that changing the low-end data point in the POD charge every time there was a change in the project database would be contrary to the objective of rate stability. Additionally, the UCA submitted that it would not be appropriate to change the low-end data point without revisiting all of the breakpoints in the POD charge.

273. IPCAA stated that the central point of the DUC evidence was that the AESO is proposing a 43 per cent reduction in the POD fixed charge.¹²⁶ IPCAA agreed that while this seemingly illogical result could be addressed by increasing the low end data point, this was treating the symptom rather than the cause. IPCAA stated that the POD cost function reflected not only the relationship between POD cost and capacity but also inadvertently reflected the relationship between POD costs over time, resulting in a higher slope to the POD cost function than was appropriate. This higher slope resulted in a lower intercept and it was this intercept that led to the reduction in the fixed charge.

274. In its argument, IPCAA included a chart illustrating a separate regression of POD costs vs. DTS capacity for three different time frames, pre-AESO, AESO to 2009 and AESO era added.¹²⁷ IPCAA explained that the first period included the largest fraction of data points at the lower end of the capacity scale, the middle period included the most data points in the mid-range of the scale while the most recent period included the most recent projects with higher costs than earlier projects. IPCAA maintained that for each of the three time periods, the slope of the cost vs. capacity curve was relatively constant. As the slope of the lines reflect the relationship between cost and capacity, IPCAA did not find it surprising that this relationship remained more constant over time than the costs themselves.

275. IPCAA observed that the AESO derived cost function shown on the chart, which encompassed all three time periods, reflected a cost vs. capacity relationship unlike that shown in any of the individual time periods. The slope of this function was steeper than that of any individual period and the AESO was deriving rates assuming that this function represented a valid relationship between POD costs and capacity.

¹²³ Exhibit No. 362.01, DUC argument, page 31.

¹²⁴ Exhibit No. 371.02, CCA argument, page 33, paragraph 89.

¹²⁵ Transcript, Volume 1, page 106, lines 4-21.

¹²⁶ Exhibit No. 367.01, IPCAA argument, page 9, refers to DUC evidence.

¹²⁷ Exhibit No. 367.01, IPCAA argument, page 10, 'Vintaged Greenfield Projects' chart.

276. IPCAA argued that the purpose of the POD cost function was to establish the economies of scale associated with POD costs and these economies of scale were largely reflected in the slope of the POD cost function.¹²⁸ IPCAA stated that calculations that distorted the slope of the POD cost function, as in this case, undermined the purpose for deriving the function. It recommended that the Commission direct the AESO to modify the derivation of the POD cost function to remove the distortion resulting from real increases in POD costs over time. If the Commission did not accept this proposal, the next best approach would be to treat the symptom rather than the cause, noting the DUC proposal to utilize a 1.5 MW low end data point would be appropriate for this purpose.

277. The UCA opposed IPCAA's recommendation that the AESO be directed to modify the derivation of the POD cost function to remove an alleged distortion resulting from increases in POD costs over time. Further, the UCA argued that IPCAA's chart and analysis, illustrating a separate regression of POD costs vs. DTS capacity, constituted new evidence and should not be considered by the Commission. On this basis, the UCA argued that IPCAA's recommendation should be rejected on the grounds that it has been presented at an inappropriate point in the proceeding, has not been properly tested, and is without proper evidentiary foundation.¹²⁹

278. The AESO also rejected IPCAA's recommendation. The AESO submitted that the cost differences noted by IPCAA in its argument submission resulted from the fact that different sizes of projects were connected during the different periods. The AESO expected that the steeper cost function over all projects reflected the economies of scale exhibited by different sizes of projects, whereas the flatter cost functions over the disaggregated groups of projects reflected the more limited size dispersions within the smaller groups. Finally, the AESO submitted that the point of delivery cost function was used to develop a point of delivery charge that applied to all services under Rate DTS regardless of size or vintage, in accordance with the "postage stamp" tariff requirement set out in Section 30 of the *Electric Utilities Act*. Therefore, the AESO submitted it was appropriate that the point of delivery cost function be determined based on data for all projects in the connection project database, as proposed in the application.

Commission findings

279. The Commission has considered the AESO's proposal to use a 0.1 MW low end point in the determination of the fixed portion of the POD cost function and the parties' positions in relation to it, particularly the DUC's proposal to utilize a 1.5 MW low end data point on the basis that it would provide for POD charges that are more consistent with prior tariffs.

280. The Commission finds merit in the DUC's objection to the use of a 0.1 MW low end point for the determination of the customer fixed charge on the basis that it would likely lead to a dramatic reduction in the fixed charge in spite of the fact that total POD costs would actually be rising.

281. The DUC asserted, supported by the CCA, that the use of a 0.1 MW low end point, and the results of it, will not accurately reflect how costs are actually incurred for new connections. The Commission notes the AESO's position that POD costs as a percentage of total transmission costs are declining and that the very small services referenced by the DUC are atypical and as a

¹²⁸ Decision 2007-106, pages 42-44.

¹²⁹ Exhibit No. 398.02, UCA reply argument, page 7.

result, it is difficult to assess if the cost function was charging an appropriate amount. Notwithstanding, the Commission agrees with the DUC that reducing the customer fixed component in the POD charge in the DTS Rate would be unreasonable in light of the increasing costs of building substations. In this regard, the Commission notes the AESO's own evidence in the application that costs are consistently rising due to inflation.¹³⁰

282. The Commission notes that the DUC has pointed out that the lowest DTS contract capacity amongst the greenfield projects is 6.0MW.¹³¹ The Commission agrees that a 1.5 MW low end data point is conservative and will provide for POD charges that are more consistent with prior tariffs.

283. With respect to IPCAA's recommendation that the AESO be directed to modify the derivation of the POD cost function to remove distortions resulting from increases in POD costs over time, the Commission finds that a direction of this nature is not necessary. In this regard, the Commission accepts the AESO's explanation that the slopes of the disaggregated groupings in IPCAA's submissions could be skewed by the size of projects in the small groups, as well as other noninflationary factors. The Commission also agrees with the AESO that the low end point should not be arbitrarily adjusted to achieve a selected dispersion of rate adjustments.

284. Additionally, the Commission also observes that setting the low end point at 1.5 MW would be more consistent with past and current rate designs and in alignment with the directions set out in Decision 2007-106 that the AESO use the lowest valued DTS contract capacity in the connection projects database.

285. In light of the considerations above, the AESO is directed to use the 1.5 MW low end data point to calculate the customer fixed charge in the POD charge in its DTS Rate in its compliance filing.

5.4 Special projects

286. In their intervenor evidence, the UCA, in both the Spragins evidence and the Power Advisory evidence, proposed treating certain bulk system projects as "special." The UCA defined special projects as those transmission projects that are driven by a reason other than the need to serve peak demand reliably. Special projects include projects driven by the need to interconnect renewable energy and provide access to the Alberta Interconnected Electric System, enable uncongested dispatch of generation under normal operating conditions, interconnect additional generation to enhance competition and market efficiency and promote government and public policies.¹³²

287. The UCA noted that the revenue requirement associated with TFO wires was increasing at a material rate and the portion of these costs functionalized as bulk was forecast to rise from 41.7 per cent in 2010 to 60.0 per cent in 2016.¹³³ Further, all bulk system wires costs were collected on the basis of 12 CP. Given the UCA's contention that many projects were built for purposes other than peak reliability, the UCA submitted that the AESO's tariff as proposed did not reflect appropriate cost recovery for special projects.

¹³⁰ Exhibit No. 26, application, Section 5.3.2, pages 34-35.

¹³¹ Exhibit No. 9, Appendix G, POD Cost Function, tab Greenfield Projects, cell X41.

¹³² Exhibit No. 147.02, Spragins evidence, page 2.

¹³³ Exhibit No. 147.02, Spragins evidence, page 2.

288. In particular, the UCA noted the AESO's legislated mandate included the requirement to plan and arrange for a transmission system that, under normal operating conditions, can dispatch all in-merit generation without constraint (regardless of location or type of generation). This legislative framework has resulted in the development of transmission infrastructure to support the competitive electricity market. As a further example, the UCA cited the Southern Alberta Transmission Reinforcement (SATR) project. In the UCA's view, it would not be reasonable to recover the costs of this project based on each customer's load during the peak hour of each month claiming the correlation between Alberta system load and wind generation was very close to zero. Therefore, the UCA considered that the costs of transmission facilities built to interconnect wind and other renewable generation should, at least in part, be recovered as an energy charge, and not almost entirely on a coincident peak basis. The UCA also maintained that the provisions of the *Transmission Regulation* militated in favour of classifying some projects as special.¹³⁴

289. The UCA proposed that three tests be applied to determine if a project was to be deemed special.

- (1) Where a project would not be undertaken, but for the need to satisfy one of these planning objectives, or government policy, then the UCA believed that the project should be deemed to be "special." For example, where a project is designed to reduce congestion within a region and increase market efficiency by reducing constraints to economic dispatch of generation, the ability to serve peak load in the region is unchanged but the efficiency of operation within the region is increased, the project should be treated as "special." For government policy triggered projects to be deemed special, their need should not be peak demand driven.
- (2) Where a project is undertaken to address system reliability, but the ultimate form of the project (e.g., configuration) is determined or strongly influenced by one of these planning objectives or government policy then it may be appropriate to deem a portion of the project's costs to be special. For example, where a project's design is determined by one of these planning objectives and this design increases the project's overall cost, the incremental cost triggered by this planning objective could be treated as "special."
- (3) Where a project is undertaken to address system reliability, but offers significant other benefits, a portion of the costs should be considered "special."

290. The UCA did not recommend that separate cost pools be established where a portion of a project's cost was deemed special, stating such an approach would be too burdensome administratively. Rather than attempt to determine the portion of project costs that were appropriately deemed special and then functionalize these costs as special, the UCA recommended that a cost allocator be used which recognized that a portion of the costs of special projects were typically energy-driven and a portion demand-driven.

291. In argument, the UCA maintained the legislated requirement in Alberta for no congestion under normal operating conditions was unique. The UCA explained that in other jurisdictions in which transmission projects were designed to reduce congestion costs, were typically only undertaken when the costs of the required facilities are less than the forecast benefits.¹³⁵

¹³⁴ Exhibit No. 147.04, Power Advisory evidence, pages 9-12.

¹³⁵ Exhibit No. 213.01, IPCAA-UCA-2.

Therefore, the Alberta legislation resulted in a higher level of transmission investment relative to other jurisdictions. The UCA was recommending that only a portion of the costs of transmission facilities that support the competitive energy market be recovered on a \$/MWh basis.

292. In reply argument, the UCA claimed it had demonstrated that the cost causation drivers for special projects were new and are resulting in more transmission being built in Alberta than would have been built in the past. The UCA reiterated the legislated requirement for no congestion under normal operating conditions was unique and resulted in a higher level of transmission investment in Alberta relative to other jurisdictions.¹³⁶ There was, therefore, a cost causation basis to classify the costs of special projects on a different basis than the costs of other transmission facilities and, in turn, to recover those costs through rates in a different manner.

293. The UCA noted that the ADC had claimed nearly all of the special projects were largely designed to enhance the reliability of the system.¹³⁷ The UCA disagreed, stating its evidence demonstrated that each special project was driven by a reason other than the need to reliably serve peak demand.¹³⁸ The UCA also noted that DUC acknowledged that the SATR project could be deemed special as it was primarily built to serve renewable generation, providing benefits to the AESO's customers in the form of lower pool prices when renewable wind sources are generating.¹³⁹

294. The UCA took issue with the DUC's submission that if a project was partially special, that did not justify collecting all of the associated costs primarily through an energy charge.¹⁴⁰ The UCA maintained the DUC misunderstood the UCA's proposed treatment of special projects. As noted in the UCA's argument, the UCA was proposing to classify only 50 per cent of the costs of special projects as energy-related.¹⁴¹

295. The CCA supported the UCA, stating that energy cost savings resulting from special projects should be reflected in an energy-related cost allocation.

296. In argument, the AESO disagreed with the UCA proposal. The AESO noted that LEI had stated:

LEI believes that special transmission projects are triggered as a result of public policy, and despite distinct purposes, arguably have similar cost causation drivers to the rest of the system... Note, however, that 'purpose' may not necessarily be the same as the 'cost causation driver'. For instance, for grid strengthening related to emissions-free projects, it may be considered prudent to recover costs from customers who are causing some environmental impact. Peak use likely causes greater emissions, which in turn drives demand for zero-emitting resources. While a line's purpose may be to serve renewables, ultimately the needs for it may be driven by peak users.

Furthermore, although a project may be built for the purposes of interconnecting renewable energy, significant portions of the project are likely to serve peak load as well.

¹³⁶ Exhibit No. 213.01, IPCAA-UCA-2 and IPCAA-UCA-9.

¹³⁷ Exhibit No. 358.01, ADC argument, page 5.

¹³⁸ Exhibit No. 147.04, Power Advisory evidence, Q/A 35- Q/A 41.

¹³⁹ Exhibit No. 362.01, DUC argument, page 6, lines 18-21.

¹⁴⁰ Exhibit No. 362.01, DUC argument, page 6, lines 12-17.

¹⁴¹ Exhibit No. 364.02, UCA argument, paragraph 38.

Similarly, projects which are built for reliability purposes may not be primarily serving peak, but in practice, are likely to still serve load in some capacity.¹⁴²

297. The AESO noted that the UCA had suggested the AESO's identification of the need for transmission facilities was now based on expanded criteria, including objectives to:

- Enable renewable energy integration and access to the Alberta Interconnected Electric System (AIES);
- Enable uncongested dispatch of generation under normal operating conditions;
- Interconnect additional generation to enhance competition and market efficiency; and
- Promote Government and public policies.¹⁴³

298. The AESO maintained, however, that the UCA had not demonstrated that equivalent or similar criteria did not exist in the past and have not historically been cost causation drivers for transmission projects. The AESO considered that the cost causation drivers for planned special projects were similar to the drivers for projects in the past.¹⁴⁴ The AESO submitted that cost causation drivers for both planned and historical projects include connecting generation, relieving transmission system constraints, and building capacity to accommodate both current and future load growth. The AESO further submitted that the only difference may be the magnitude of projects that are currently planned, and this was not a sufficient basis to support a change to the functionalization of certain transmission projects.

299. The ADC supported the views of the AESO, stating that parties' requests to identify certain transmission projects as "Special" and provide different cost allocation and rate designs were inappropriate. The ADC maintained nearly all of the special projects identified by the parties were largely designed to enhance the reliability of the system. Hence, there was no legitimate reason to conclude that these projects were special, but rather, as part of the system needed to enhance system reliability to meet the current and projected load on the transmission system. Further, some transmission projects such as the SATR project, were developed in order to connect wind power to the transmission system. The initial development of this system was not done to enhance system capacity, but rather to tie generation resources to the load centers. The ADC stated this was consistent with the original development of many parts of the transmission system that were now included in the bulk and regional transmission network. The ADC maintained this characterization alone was appropriate for including these transmission assets along with all other bulk transmission systems, in allocating its costs and designing cost recovery rates based on the same principles as the remaining bulk transmission system.

300. In reply argument, the ADC stated the needs identification documents of certain projects had been cited in this case, and maintained increased system reliability remained a significant benefit for all transmission projects. The ADC submitted the core issue to be determined centered on the identification of what were the cost drivers of transmission projects, and how were the specific installed transmission assets sized and their need established. The ADC maintained all of these benefits were realized by the expected transmission demand at the time of the system peaks.

¹⁴² Exhibit No. 265.02, Cost Causation Study, pages 77-78, lines 1752-1767.

¹⁴³ Exhibit No. 147.04, Power Advisory evidence, pages 6-7.

¹⁴⁴ Transcript, Volume 3, pages 413-415.

301. The ADC also noted the UCA had stated that the objectives satisfied by a transmission project can change over time and, therefore, the determination of a special project would only be established for a given test year period.¹⁴⁵ Taken to its logical end, the ADC suggested this would create a litigated issue in every single AESO rate case for all transmission assets currently installed and those planned and included in the test year period. The ADC also stated if, as UCA suggested, the “cost benefits of Special Projects might change over time, then it seems other transmission projects, not currently deemed Special Projects, might also morph to require the designation as Special Projects.”¹⁴⁶

302. Finally, the ADC stated the UCA’s argument was not based on cost causation and was, therefore, contrary to the established goals of cost allocation. The ADC acknowledged the benefits of a transmission asset to the system may indeed change over time, but claimed the cost causation of the investment would not change. In the ADC’s view, when cost allocation is based on cost causation of the assets, the cause of the installed asset will not change over time, and cost allocation would not adjust and not necessitate re-litigation at every rate proceeding. This properly allocated cost on cost causation and stabilized the transmission rate process.

303. The DUC also supported the view of the AESO, stating there was no need for transmission projects to be classified as “special.” The DUC noted the issue was addressed by LEI, an independent expert, who determined for the cost causation study that there was no basis for any differentiation amongst transmission projects.¹⁴⁷

304. The DUC maintained the UCA proposed “special” project definition was far too encompassing. The costs associated with transmission projects built for load, base load generation, and/or reliability concerns should not be collected from the AESO’s customers based primarily on an energy charge. To do so, in the DUC’s view, would be a major departure from the classification and collection of costs under current and prior AESO tariffs.

305. Finally, the DUC stated that even if a project was partially justified based on some “special” criteria, for example compliance with the *Electric Utilities Act* and the *Transmission Regulation*, most of the “special” projects identified by the UCA were also justified based on “conventional” criteria, like load or generation additions or system reliability. The DUC maintained that if a project was partially “special,” that did not justify deeming the entire project “special,” and collecting all of the associated costs primarily through an energy charge.

Commission findings

306. In evidence, the UCA has proposed designating certain transmission projects as special and allocating a portion of their cost on an energy basis. The UCA also proposed a three-part test to determine when a project would be designated as special, primarily when a project is driven by a reason other than to serve peak load reliably. The AESO rejected the proposal of the UCA, claiming that the UCA had not demonstrated that equivalent or similar criteria did not exist in the past and have not historically been cost causation drivers for transmission projects.

¹⁴⁵ Exhibit No. 364.02, UCA argument, page 9, paragraph 40.

¹⁴⁶ Exhibit No. 393.01, ADC reply argument, page 5.

¹⁴⁷ Exhibit No. 7, Appendix E, Transmission Cost Causation Study, page 79, lines 1780-1795.

307. The Commission considers the following testimony of Mr. Martin regarding cost causation drivers to be persuasive.¹⁴⁸

Q: So special projects, could you please -- actually I don't think you need to turn this up. I'll just give you the quotation: (as read)

“At page 77 of the updated LEI study, LEI states that while some projects could be classified as special, LEI considered them to have the same cost causation drivers to the rest of the system and proposed no special treatment.”

Does the AESO agree that the these projects do have the same cost causation drivers?

A. MR. MARTIN: We think so, yes. When we look back at the history of the transmission system and say why have various transmission lines been installed – for example, the KEG loop that we just looked at, why was the KEG loop installed? Well, the KEG loop was installed to connect generation. The fact that other lines are being built to allow the connection of generation today doesn't seem any different than those lines being built to connect those generators years ago. Other lines that are built to relieve constraints in an area, the nature of the network system is that we've always built lines to allow different flows of electricity on the bulk system so that we can continue to operate the system during contingencies. The concern with lines being built for load growth that will occur over many years, that's always been an issue with the bulk transmission system. The nature of large capacity transmission additions is that it's lumpy. You get a lot of capacity initially because it's economically efficient to build it all at once. So those things do seem a continuation of previous reasons for building the bulk transmission system, and it doesn't seem like there's enough of a difference to identify these current projects as unusual from past projects. Perhaps the different part is that there seems to be a lot of them going ahead at the same time, and 30 years ago they seemed to be spread out over a longer time span.

308. The Commission considers the types of projects the UCA would propose to classify as special have the same cost causation drivers as historical projects. The Commission also accepts the arguments of the ADC that the determination of projects as special and how that status may change over time could be contentious. For the above reasons, the proposal of the UCA to classify projects as special is rejected.

5.4.1 Classification of special project costs – average and excess method

309. In its evidence, the UCA proposed to classify special project costs between energy and demand using the average and excess (A&E) method. The UCA noted the AESO proposed using the A&E method to allocate bulk and local wires costs in its 2007 GTA application. The EUB rejected the use of the A&E method in its decision approving the AESO's GTA application with modifications, accepting the arguments posed by various parties that opposed this method. The UCA noted one criticism of the A&E method was that it was generally used “to allocate generation costs, and a methodology used for generation is not necessarily warranted for

¹⁴⁸ Transcript, Volume 3, pages 413-415.

allocating transmission costs.”¹⁴⁹ The UCA maintained using the A&E for cost recovery for special projects was different.

310. The UCA described the A&E method as a demand-related cost allocator, which recognized that a portion of fixed costs are energy-related and the remainder demand-related. Under the A&E, the energy-related component of fixed costs was established based on the system load factor and the demand component was allocated using excess demand.

311. The UCA acknowledged that wires costs were largely fixed. However, for special projects, the UCA maintained the primary contributors to the need for the projects were not demand-related. The UCA stated growth in peak demand did not drive the need for most special projects, growth in energy requirements typically drove the need. Therefore, it was appropriate to recover a portion of these projects costs through an energy charge.

312. The UCA acknowledged a case could be made that the appropriate energy and demand weighting should vary by project, with a project such as SATR warranting a higher energy weighting than the east and west HVDC facilities. From this perspective, the A&E method was an approximation of the appropriate cost responsibility. The UCA stated that, while this approach was intuitively appealing, since in theory cost allocation would more closely follow cost causation, establishing cost causation for such facilities was difficult and imprecise. Furthermore, implementing such an approach would require significant resources, with the range of plausible assumptions providing a wide range of outcomes.

313. In argument, the UCA acknowledged that, in certain circumstances, the use of the A&E method to determine the portion of the costs for a particular special project that should be classified to energy may produce results that are counterintuitive.¹⁵⁰ While even in these circumstances, assigning some costs to energy would be appropriate, the UCA acknowledged that the A&E method may not produce results that would be more appropriate than a 50/50 split, which would eliminate the need for detailed calculations. In the UCA’s view, the alternative to 12 CP could be either the A&E method or a 50/50 split of demand and energy-related costs.¹⁵¹

314. The UCA noted some parties appeared to be concerned about the price signal that the UCA’s proposal would send. UCA submitted that implementation of its proposal, with respect to special projects, would not decrease the incentive that customers currently have to avoid using the bulk system during the coincident peak hour of each month. In fact, given the huge growth in bulk system costs, the UCA maintained the price signal to avoid the peak hour will grow stronger and stronger, whether or not the UCA’s proposal is adopted.

315. The UCA agreed with the AESO that there were no insurmountable practical problems with identifying special projects.¹⁵² Once special projects have been identified, determining the effect of special projects on the functionalization and classification of bulk system costs is straightforward.¹⁵³

¹⁴⁹ Decision 2007-106, page 28.

¹⁵⁰ Exhibit No. 209.01, AUC-UCA-1.

¹⁵¹ Exhibit No. 209.01, AUC-UCA-1.

¹⁵² Transcript, Volume 3, page 415, lines 11-19.

¹⁵³ Exhibit No. 147.04, Power Advisory evidence , page 31, A43.

316. In reply argument, the UCA noted that the AESO had submitted the A&E method was not based on cost causation since the use of load factor to determine the energy-related component is inconsistent with the cost causation driver for high load factor transmission facilities.¹⁵⁴ The UCA explained, as noted in response AUC-UCA-1(b), that Power Advisory was reluctant to put forward a classification method that did not have some form of analytical support and acknowledged that the A&E method would yield counterintuitive results if project-specific load factors were utilized. The UCA further explained that Power Advisory was not proposing project specific load factors. Rather, it was important that an alternative to 12 CP be employed that recognized that a significant portion of the costs of special facilities was appropriately classified as energy-related. The UCA clarified it was now proposing a 50/50 split of demand and energy-related costs for those projects identified as special by Power Advisory, as stated in the UCA's argument.¹⁵⁵

317. In argument, the CCA supported the UCA's initial proposal to use the A&E method to classify special project costs. The CCA maintained it was appropriate to reflect the energy cost savings resulting from special projects as energy related, in rate design, as it provided appropriate price signals.

318. In reply argument, the CCA had no comment upon the UCA's revised position to use a 50/50 demand/energy classification factor in place of its original proposal to use the A&E methodology.

319. In argument, the AESO maintained that classification through an average and excess method is not based on transmission cost causation and should be rejected. The AESO explained the energy component of special projects would be based on load factor. Therefore, the higher the load factor, the greater the proportion of costs that would be classified as energy-related. Yet a high load factor was typical of transmission facilities built to serve load, and the UCA proposes that special projects "are built for reasons other than to reliably serve load."¹⁵⁶ The AESO submitted that the use of load factor to determine the energy-related component is clearly inconsistent with the cost causation driver for high load factor transmission facilities.

320. The AESO noted that, under cross-examination, the UCA clarified its proposed average and excess method used "a length weighted line load factor" based on all bulk system transmission lines, rather than one based on the special projects themselves.¹⁵⁷ The AESO further noted the UCA suggested that a key characteristic of the special projects it has identified is that they have resulted from "a significant change in the transmission investment drivers and ... the development of transmission projects for new reasons."¹⁵⁸ The AESO submitted it was contrary to the principle of cost causation to first define special projects as different from conventional projects, and then to classify the costs of those special projects based on conventional projects (which comprise the majority of all bulk system transmission lines on which the line load factor was based).

¹⁵⁴ Exhibit No. 366.01, AESO argument, paragraph 92.

¹⁵⁵ Exhibit No. 364.02, UCA argument, paragraph 38.

¹⁵⁶ Exhibit No. 147.04, Power Advisory evidence, page 12.

¹⁵⁷ Transcript, Volume 7, pages 1022-1023.

¹⁵⁸ Exhibit No. 147.04, page 12.

321. Finally, the AESO also suggested the A&E method itself was poorly defined. The AESO noted the UCA agreed in cross-examination that there was no accepted standard for an average and excess method¹⁵⁹ and that it “would be cleanest if one were to use the average load factor for these special projects.”¹⁶⁰ Further, as was revealed in the UCA’s responses to information requests, the proposed approach addresses neither the fact that the objectives satisfied by a transmission project can change over time,¹⁶¹ nor that a portion of a project’s costs could be deemed special.

322. In reply argument, the AESO noted the UCA had in argument proposed a 50/50 demand/energy cost classification for special projects. The AESO maintained this ran directly counter to an earlier section of the UCA’s argument where it stated that “the public interest would be best served by establishing a rate structure that recovers costs in a manner consistent with what drives the need for facilities. Such a rate structure would be just and reasonable and therefore in the public interest.”¹⁶² The AESO submitted that the UCA had not demonstrated that an arbitrary 50/50 demand/energy cost classification recovered costs in a manner consistent with drivers of need. Accordingly, on the basis of the UCA’s own evidence, the AESO submitted that establishing a rate structure on such an arbitrary basis would not best serve the public interest.

323. In argument, the ADC noted that the UCA had not provided any indication of customer bill effects based on its proposed A&E allocation method,¹⁶³ as it could not produce the proper energy/demand cost split that would result from its proposed methodology.

324. The ADC stated that clear price signals to customers are essential to enhancing demand conservation and promoting efficient use of the bulk transmission system, noting there was no proof an energy based cost recovery method would result in better price signals or more efficient investment decisions. In the ADC’s view, customers could make economically sound decisions regarding potential investments in equipment or operation modifications in order to reduce peak demand only if their electric rates were designed properly to provide a pay-back for their efforts. Using a billing determinant based on customer average and excess load to assess bulk transmission charges would likely make it more difficult for customers to fully analyze the economics of those potential investments to reduce electric costs. The ADC submitted continued use of the 12 CP allocation method would ensure stable and understandable price signals to customers.

325. In reply argument, the ADC noted that the UCA had backed away from the A&E method and was advocating a 50/50 demand/energy cost classification split. ADC termed the 50/50 proposal arbitrary and stated such an allocation simply reinforced the reality that there was significant uncertainty surrounding the extent to which additional energy-related cost causation existed for these special projects. The UCA’s proposal was not based on cost causation and should, therefore, be rejected.

¹⁵⁹ Transcript, Volume 7, page 1021.

¹⁶⁰ Transcript, Volume 7, page 1023.

¹⁶¹ Exhibit No. 212.01, AESO-UCA-001.

¹⁶² Exhibit No. 364.02, UCA argument, paragraph 15.

¹⁶³ Exhibit No. 147.04, Power Advisory evidence, page 31.

Commission findings

326. In Section 5.4 of this decision, the Commission rejected the proposal of the UCA to classify certain projects as special. The Commission, therefore, does not consider it necessary to address the A&E methodology at length.

327. The Commission notes that the UCA backed away from using the A&E methodology in its argument,¹⁶⁴ stating its use required detailed calculations and may produce results that are counterintuitive. Given that the methodology's own sponsor finds its use problematic, coupled with the Commission's own findings regarding the difficulty that could arise in attempting to classify certain projects as special, the Commission does not approve the UCA's proposed A&E methodology.

328. The UCA proposed, as an alternative, that a 50/50 demand /energy split could be used as a reasonable proxy that would not require calculations. However, this proposal was not made until final argument. As such, parties had no opportunity to ask questions or test this alternative proposal. For this reason, the Commission has not considered this alternative proposal in this proceeding.

5.5 Difference between Rate STS and Rate IOS

329. In its intervener evidence, ATCO Power stated that the treatment between supply transmission service (STS) customers, generators, and import opportunity service (IOS) customers, importers was unjustly discriminatory. In particular, ATCO Power stated that STS and IOS customer groups pay effectively the same rate and receive effectively the same service but Rate STS customers face significant additional obligations in comparison to Rate IOS customers.

330. ATCO Power stated the nature of the unjust discrimination was found in ISO Rule 203.1.¹⁶⁵ Section 3(1) of the rule created an obligation for virtually all source assets, including imports, that required all source assets to have offers submitted for them and Section 3(4)(a) created the obligation for these mandatory offers to cover the maximum capability of the source asset. Section 5 created a further obligation for these source assets to submit their available capabilities.

331. ATCO Power maintained that by tracing the terms used in sections 3(1), 3(4)(a) and 5 of ISO Rule 203.1, it was evident that for generating units, who are the Rate STS customers, their obligation was to make the entire physical capability of the asset available to the power pool at all times. Conversely, for import assets, who are the Rate IOS customers, there was effectively no obligation to make the entire physical capability of the asset available to the power pool at all times since Rate IOS customers only need offer as much as they choose to offer. In ATCO Power's view, this meant that, effectively, there were no capacity obligations for Rate IOS customers. Those suppliers were free to sell rights to their capacity in other jurisdictions. Conversely, signing up for Rate STS on the other hand assigned the right to the entire capacity of the generator to the Alberta power pool, thereby negating any opportunity for the Rate STS customer to otherwise profit from its capacity.

¹⁶⁴ Exhibit No. 364.02, UCA argument, page 8, paragraph 38.

¹⁶⁵ Attachment 21, ISO Rules Part 200 Markets – Division 203 Energy Market: Section 203.1 Offers and Bids for Energy (January 8, 2013).

332. ATCO Power presented four options to remedy this unjust discrimination:

- (a) Remove the capacity obligation for Rate STS customers – by removing the capacity obligation for Rate STS customers, these suppliers would have the option of selling their capacity either domestically or out of province. Rate STS customers would be allowed to physically withhold generation and to schedule non-recallable exports out of Alberta.
- (b) Place a capacity obligation on Rate IOS customers – importers would be required to commit their capacity long term to Alberta. This would place the importers on a level playing field with Alberta generators, who are not permitted to otherwise sell available capacity. This option would require coordination with other jurisdictions to enable firm transfer commitments all the way from the source asset to Alberta. Presumably, there would initially be no uncommitted capacity available for imports into Alberta, and consequently there would only be a small amount or no imports until this capacity is developed.
- (c) Lower Rate STS to reflect the capacity obligation – lowering Rate STS to account for the significant additional obligation imposed on Rate STS customers would transform this rate into an overall credit to these customers. The credit could reflect either the cost or value of the capacity they provide. ATCO Power maintained this option would effectively transform Alberta's electricity market from an "energy only" design into an "energy plus capacity" design.
- (d) Increase Rate IOS to reflect the absence of the capacity obligation – under this option, a higher rate would be charged to Rate IOS customers to reflect the value or the cost of the additional obligation imposed on Rate STS customers.

333. ATCO Power considered alternative (d) to be the most efficient option and consistent with the Alberta electricity market and recommended that the Commission direct the AESO to examine this option as a way to eliminate what it asserted to be the unjustly discriminatory treatment between Rate STS and Rate IOS customers. ATCO Power suggested auctioning available transfer capacity and distributing the revenues to consumers would address most of its concerns.

334. In its argument, ATCO Power further asserted its views regarding the discrimination it considered was visited on Rate STS customers. It claimed that the must-offer/must comply obligation (the obligation) was significant to Rate STS customers. ATCO Power noted that exports were curtailed first during periods of supply shortfall in Alberta. ATCO Power explained that this restriction prevented generators in Alberta from exporting when the price in neighbouring jurisdictions was above \$1000/MWh, thereby disallowing generators from realizing additional value from their Alberta assets when prices were above this level outside Alberta. ATCO Power stated these foregone opportunities could be significant.

335. ATCO Power maintained that the ability to economically withhold capacity when the price was below the cap was irrelevant. ATCO Power explained the ability to economically withhold allowed Alberta generators to receive payment in Alberta for the capacity they are committing to Alberta without relying exclusively on supply shortfall conditions. Importers receive this payment without having to commit their capacity. Unlike Alberta generators who cannot secure capacity payments externally, ATCO Power stated the importers were free to do so.

336. ATCO Power acknowledged that in Alberta behind-the-fence arrangements can be made, where long-term off-take contracts with site hosts can be negotiated. These contracts included payments to the generator towards the recovery of the capital costs. However, generation that is behind-the-fence is not sold to the pool and is not subject to rate STS. To the extent these assets were part of a behind-the-fence arrangement, the only opportunity to recover capital costs was the contracts negotiated between the generator and the host. That is, the generation did not receive the pool price or the capacity component embedded therein. To the extent that such a behind-the-fence facility is able to generate revenue from selling to the pool and that revenue will contribute to the cost of the facility, both the generator and the host would take that into account. Alberta generators were, therefore, only able to recover their capacity costs once and only once.

337. ATCO Power also maintained the obligation was significant to consumers as well. ATCO Power explained that in an energy-only market like Alberta's, consumers effectively paid for capacity when the price was above marginal cost of production. In the long term, however, where not only domestic generation investments, but also new intertie developments can be considered, imposing the obligation only on Rate STS customers without adjusting the rates accordingly has a profound effect: increased imports displace potential generators resulting in a decline of the share of committed capacity in Alberta and a corresponding decrease in reliability.¹⁶⁶ Furthermore, the resulting pool price will not be lower. ATCO Power also maintained there was no significant difference in the two rates that would counteract the unjust discrimination brought about by imposing the obligation only on Rate STS customers.

338. ATCO Power noted another issue raised with respect to the significance of curtailments related to the pool prices in Alberta when import available transfer capacity was affected due to Calgary area constraints. The suggestion was that Calgary area constraints resulted in curtailments in a significant number of hours when the pool price was above average, thereby disadvantaging Rate IOS customers. Based on the information provided in Table 1 in Exhibit 299, hours with Calgary area constraints are associated with a pool price that was \$5 higher than the average pool price.¹⁶⁷ Given that in ATCO Power's view, the capacity component in the pool price was what consumers pay for committed capacity, imports should not be eligible for the capacity component in the first place. In this context, ATCO Power submitted that, whether some amount of imports are not able to capture the entire capacity component, was beside the point. In summary, while the curtailments may not be negligible per se, ATCO Power maintained their value was minimal in comparison to the value of the obligation.

339. ATCO Power also noted that parties had raised the issue of the AESO's obligation to plan for unconstrained transmission access for Alberta generators. ATCO Power considered the AESO's obligation to plan for unconstrained transmission access to be a necessary requirement for Alberta generators to be willing to invest in an energy-only market where there are no guaranteed payments for capacity. Transmission access ensured access to pool price, especially in those hours where pool price contributed to the recovery of fixed costs. For a potential investment in an energy-only market, better transmission access meant better opportunities to recover costs. This, in turn, lowered the investment risk and the borrowing costs that constituted part of the associated capital costs.

¹⁶⁶ Exhibit No. 298.02, ATCO Power opening statement, paragraph 9.

¹⁶⁷ Exhibit No. 299.01, TCE aid to cross.

340. ATCO Power explained that absent the AESO's obligation to decongest the transmission system for generators, investors' cost of capacity would be higher, resulting in increased long-term pool prices and potentially, underinvestment in Alberta based generation. Therefore, the AESO's obligation towards Rate STS customers served to achieve an important outcome in market design, namely sufficient investment in generation at the lowest possible cost to consumers. ATCO Power maintained generators were not receiving net benefits from an unconstrained transmission system. In the absence of an unconstrained system, generators would include the uncertainty associated with the level of system access service in their risk premium and would adjust their investment in a way that would allow them to recover this risk premium from consumers.

341. ATCO Power did acknowledge the obligation could be considered to address market power issues that may arise in the context of transactions outside the power pool. For example, without the obligation, generators may be able to receive more than \$1000/MWh from consumers through out of market agreements in the face of supply shortfall.

342. ATCO Power also addressed the presumed benefits of imports, stating that the alleged benefits of imports in Alberta were not based on fact, and were largely non-existent. ATCO Power suggested the main perceived benefit of imports was lower pool prices. This perception was presumably¹⁶⁸ based on imports being offered at \$0, and the observation that pool prices in Alberta rise during intertie outages.

343. ATCO Power explained the fact that imports are offered at \$0 reflected scheduling restrictions over the ties. Similarly, due to physical constraints or steam contracts with hosts, a significant amount of energy was offered at that price by many generating units in Alberta. ATCO Power pointed out, however, that unlike the Alberta capacity that is offered at \$0, importers choose when to schedule imports on a voluntary basis. While they are price takers once they decide to import, they decide whether to import; and they do so only when the expected pool price is sufficiently high for them to profit from the transaction.¹⁶⁹

344. In argument, the AESO submitted that an ISO tariff proceeding was not the appropriate forum in which to address concerns arising from the requirements of an ISO rule. A distinct process for such concerns is set out in sections 20.4 and 25 of the *Electric Utilities Act*.

345. The AESO stated that pursuant to Section 30(2) of the *Electric Utilities Act*, the rates to be charged by the AESO for Rates IOS and STS must be reflective of the costs reasonably attributable to these rate classes for providing them with service through a connection to the transmission system. The AESO submitted that Rates IOS and STS were just and reasonable and largely the product of express requirements under the *Transmission Regulation*.

346. The AESO maintained neither the system access service received nor the rates paid under Rates IOS and STS were the same. In particular, the AESO explained Rate IOS was an opportunity service that was only available when sufficient capacity exists to accommodate the capacity scheduled for import. Further, Rate IOS customers are curtailed before Rate STS

¹⁶⁸ AESO analysis underlying UCA-AESO-1; Transcript, Volume 5, page 683, lines 1-3; EnerNOC response to CCA-EnerNOC-1.

¹⁶⁹ Transcript, Volume 5, page 682, lines 2-13.

customers in times of transmission constraints and in times of supply surplus under ISO rules 302.1 and 202.5, respectively.

347. The AESO explained the requirement that generators offer the entire physical capability of their source assets to the power pool was in place to address market power issues by preventing physical withholding. A generator can offer its capacity at any price and it can choose to deliver its capacity to the Alberta market, or to export it. ATCO Power's suggestion that ISO Rule 203.1 negates any opportunity for a generator to otherwise profit from its capacity ignores the fact that Rate STS customers have significant opportunity to export their capacity should they wish to.

348. The AESO also submitted that ATCO Power's suggested options for eliminating unjust discrimination were problematic and should not be adopted. Removing the must-offer/ must-comply provisions applicable to Rate STS customers in ISO Rule 203.1 would expose the energy market to concerns of physical withholding and market power while placing a capacity obligation on importers would effectively close the border to imports. Reducing Rate STS by making it a credit that would reflect the value of capacity provided would effectively transform Alberta's energy-only market into an energy plus capacity market and increasing Rate IOS to reflect the value of the additional obligation imposed on Rate STS customers was inconsistent with the principle of cost causation. It also appeared to be contrary to Section 30(2) of the *Electric Utilities Act*, which requires that costs collected from a rate class be only those costs reasonably attributable to providing them with service through a connection to the transmission system. Finally, the AESO noted ATCO Power's proposed auction option in which Rate IOS customers would pay for available transfer capability has been previously proposed by ATCO Power and rejected by the Commission in Decision 2013-025,¹⁷⁰ AESO - Objections to ISO rules Section 203.6 Available Transfer Capability and Transfer Path Management.

349. The AESO noted that ATCO Power had claimed the benefits of imports were non-existent and that increased imports displace potential generators resulting in a decline of the share of committed capacity in Alberta and a corresponding decrease in reliability. The AESO did not agree and explained that while the generation industry may adjust its investment slightly to compensate for potential opportunity imports, import supply was additive to the supply curve and when an import provided energy to the market, that supply had a market price effect, which was a savings to all consumers in that hour.¹⁷¹ Further, given the opportunity nature of imports, economic signals would not support a delay or decrease investment to offset potential imports.¹⁷² Moreover, these claims were not relevant to the issue of whether Rates IOS and STS for system access service were just and reasonable or whether there was unjust discrimination against Rate STS customers, as ATCO Power has alleged.

¹⁷⁰ Decision 2013-025: Alberta Electric System Operator, Objections to ISO rules Section 203.6, Available Transfer Capability and Transfer Path Management, Application Nos. 1607958, 1607986, 1607987, 1607988, 1607993 and 1608013, Proceeding ID No. 1633, February 1, 2013.

¹⁷¹ Transcript, Volume 3, page 329 and Exhibit No. 264.02, AESO rebuttal evidence, paragraph 21.

¹⁷² Transcript, Volume 3, page 330 where the AESO explained that "in the AESO's evaluation of the reserve margins and adequacy of supply, which is public information, the numbers related to certain variables of investment are discounted, numbers like a transmission capacity product like intertie or numbers associated with wind which has a different capacity factor. So any evaluation of the opportunity or the potential for competition related to generation in the market is evaluated based on the type of that supply, so an intertie announcement would be assessed within that context."

350. The CCA agreed with the AESO. It noted there were capacity mechanisms available to Alberta generators to strengthen incentives for investment, such as forward contracting. It also noted that while market rules required generators to make their capacity available to the Alberta market, a degree of economic withholding was allowed as generators were free to set their own offer price up to \$999.99/MWh.

351. Powerex also disagreed with the position of ATCO Power, stating that Rates STS and IOS were not the same nor did they have the same attributes of service. Rate IOS was an opportunity service while Rate STS was essentially firm. Rate IOS customers were subject to curtailment ahead of Rate STS customers if supply needed to be backed down. Additionally, the AESO was required to build transmission to serve STS customers' capacity. Powerex maintained there was no evidence to support ATCO Power's contention that importers were able to recover their capacity costs in other markets and that this was somehow discriminatory. Powerex also stated that while importers may at times be able to pursue opportunities in other markets that Alberta generators may not be able to, this was due to the location of those importers, not the working of ISO Rule 203.1. Powerex also claimed that Alberta generation had opportunities that it could pursue in ways that ex-Alberta generation could not.

352. TCE maintained that the issue between Rates IOS and STS was not with respect to the product each delivered, but, rather, the system access service each received from the AESO. They were fundamentally different as Rate IOS was an opportunity service while STS was not. TCE also noted that while ATCO Power acknowledged Rate IOS customers were curtailed prior to STS customers, it maintained that curtailments during times of Calgary constraints constituted a negligible restriction that generally applied in the least valuable hours. TCE claimed there was no evidence on the record to demonstrate either the existence or extent of this opportunity cost. In particular, ATCO had not adduced any evidence of where the energy price in a neighbouring jurisdiction had exceeded \$1000/MWh during a supply shortfall event in Alberta. In contrast, TCE noted that importers were curtailed prior to STS customers during times of system constraints TCE referred to its Exhibit No. 299 which showed that there were Calgary area constraints in 739 hours and that, in 2013, the average pool price when there were Calgary area constraints (during which time Rate IOS customers are curtailed before Rate STS customers) was greater than the average pool price for all hours in that year (\$85.55 vs. \$80.19). TCE asserted that this exhibit refuted the suggestion that curtailment of Rate IOS service during Calgary area constraints was negligible because it only occurred rarely or when prices were low.

353. In reply argument, ATCO Power acknowledged that it could export power and was not ignoring "the fact that Rate STS customers have significant opportunity to export their capacity should they wish to,"¹⁷³ as claimed by the AESO. The fact was irrelevant. ATCO Power stated the value of capacity to the buyer came from firm commitments. As the obligation only made export capacity available on a non-firm basis, it eliminated virtually all the residual value of exports.

354. ATCO Power also noted the AESO had claimed that ATCO Power's proposed option was not consistent with cost causation and was in violation of the *Electric Utilities Act*. ATCO Power disagreed, noting that the absence of the obligation for Rate IOS customers meant that they do not commit their capacity and hence do not provide the same level of reliability. This

¹⁷³ Exhibit No. 366.01, AESO argument, paragraph 177.

imposed a cost in the form of a risk on Alberta consumers and this cost was caused by the importers' inability or unwillingness to commit their capacity. The principle of cost causation, therefore, suggested that this cost should be charged to importers and refunded to consumers. ATCO Power also noted that Section 30(2) of the *Electric Utilities Act* only specified the minimal costs that should be recovered in a rate. There was nothing in the legislation suggested that these were the only items that could be charged. Finally, ATCO Power noted that in Decision 2005-096,¹⁷⁴ the Alberta Energy and Utilities Board (board or EUB) determined that "opportunity rates should be reasonably flexible so as to maximize their revenues and consequent contribution to overall costs."¹⁷⁵ ATCO Power noted similar comments in Decision 2007-106.¹⁷⁶

355. ATCO Power noted the CCA had stated that despite any perceived uneven playing field, EPCOR was still willing to invest.¹⁷⁷ In ATCO Power's view, the fact that new investments are being considered is not sufficient evidence that the unjust discrimination does not or cannot affect dynamic efficiency. ATCO Power explained regardless of subsidies to, or the preferential treatment of, a particular supply source (that is limited in magnitude), long-term pool price reflects the cost of new entry in Alberta. When the expected price level justifies the costs of a new investment, the investment will take place. Given sustained load growth in Alberta, it should not be surprising that investors are looking to invest in this market. While subsidies or preferential treatment creates winners and losers among the suppliers, it leaves the long run pool price unchanged.

356. With respect to the difference between Rates STS and IOS, ATCO Power noted that it had acknowledged that IOS customers were curtailed prior to STS customers at times of constraint. However, ATCO Power put this in context, noting that for most of the constraints in the province, curtailments of imports were not effective in alleviating the constraint.¹⁷⁸ It is not the case that Rate IOS customers were curtailed more often than Alberta generators in constrained areas in the province. Second, TCE's aid to cross¹⁷⁹ does not contain volumes of curtailed imports. It would be wrong to interpret the numbers as if – whenever there is a Calgary area constraint – all imports are curtailed. This also meant that calculation of the pool price difference simply by averaging over hours (instead of weighing it by volume) was misleading.

Commission findings

357. As set out in Section 3.1 of this decision, the Commission's oversight of the components that make up the AESO tariff in a tariff proceeding is reflective of the legislative scheme. Section 121 of the *Electric Utilities Act* requires the Commission, when considering whether to approve a tariff application, to ensure, *inter alia*, that the tariff is just and reasonable and that the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any enactment or law. Consequently, the Commission considers that in approving an AESO tariff, it must be satisfied that the AESO has complied with the legislative

¹⁷⁴ Decision 2005-096: Alberta Electric System Operator (AESO), 2005/2006 General Tariff Application, Application No. 1363012, August 28, 2005.

¹⁷⁵ Decision 2007-106, page 41, paragraph 3.

¹⁷⁶ Decision 2005-096, page 91, paragraph 4.

¹⁷⁷ Exhibit No. 371.02, CCA Argument, paragraph 96.

¹⁷⁸ Exhibit No. 239, AESO-ATCOPOWER-001(c).

¹⁷⁹ Exhibit No. 299.01.

requirements imposed on it as directed by the *Electric Utilities Act* and the *Transmission Regulation*.

358. ATCO Power's position that the STS Rates and IOS Rates are discriminatory is predicated on an assumption that Rate STS customers and Rate IOS customers receive effectively the same level of service. Applying this assumption, it is the view of ATCO Power that Rate STS customers should not pay a similar rate as that paid for by Rate IOS customers because IOS customers do not have to commit all of their capacity whereas STS customers must do so pursuant to ISO Rule 203.1. Consequently, ATCO Power has proposed that Rate IOS should be adjusted upwards to reflect this different treatment of capacity.

359. Opponents of ATCO Power's position, IOS customers and the AESO, acknowledge the capacity offer obligations imposed by ISO Rule 203.1 are different, but do not accept the proposition that STS customers and IOS customers receive the same level of service. Rather, they assert that the rate established for Rate IOS services reflects the costs these customers impose. Further, as IOS is an opportunity service, IOS customers are curtailed prior to STS customers either during times of constraint or during times in which there is a supply surplus.

360. ATCO Power has argued that these differences are not material. The Commission does not agree. The Commission has considered the evidence and submissions of the parties and finds that STS customers and IOS customers do not effectively receive the same level of service. The Commission has reached this finding on the basis of the following facts: (1) TCE's evidence respecting curtailment activity is illustrative of some degree of different service levels because Rate IOS customers have been curtailed during times of constraint, regardless of whether the constraint is alleviated, prior to curtailment of STS customers; and (2) IOS customers are price takers, whereas STS customers are price-setters. The Commission accepts the AESO's assertion that those differences, and rates established for those different services, reflect the prudent costs reasonably attributable to each rate class as required by Section 30(2) of the *Electric Utilities Act*.

361. As the underlying premise in support of ATCO Power's claim that the IOS rate is discriminatory and unjust as compared to the STS rate has not been accepted by the Commission, there is no basis to conclude that the IOS rate is discriminatory and unjust.

362. The Commission has provided its finding in this proceeding respecting whether the IOS Rate is discriminatory pursuant to the Commission's legislative oversight of the AESO tariff. Included in its submissions, ATCO Power has asserted that unjust discrimination arises between the Rate STS and Rate IOS customers from the must offer-must comply requirements found in ISO Rule 203.1. The AESO responded by arguing that a tariff proceeding is not the proper forum in which issues respecting the operation of its rules should be addressed. The Commission agrees with the AESO that an ISO tariff proceeding is not the forum in which to address concerns arising from the operational requirements of an ISO rule. The legislation clearly establishes recourse to parties who have an objection to a proposed rule or a complaint regarding the operation of an existing rule in sections 20.4 and 25, respectively, of the *Electric Utilities Act*. To the extent that ATCO Power takes issue with the operation or application of a particular ISO Rule, those issues should be advanced in that forum.

5.6 Load shed service for imports

5.6.1 Background

363. The AESO describes load shed service for imports (LSSi) as:

... an armable load shed service designed to increase import capability into Alberta across interconnections with other jurisdictions that are part of the Western Electric Coordinating Council (WECC). Available LSSi load is incorporated into the determination of import capability made available to market participants. Loads providing LSSi are then armed as required on an hourly basis based on the actual scheduled volume of imports. Loads armed to provide LSSi are automatically tripped should the Alberta interconnected electric system frequency fall below 59.9 Hz.¹⁸⁰

364. According to the AESO:

The role of LSSi is to increase the import capability of the Alberta transmission system under normal conditions. LSSi is a load shed product that is planned to operate (that is, to trip the LSSi load) when an under frequency condition occurs as a result of a controlled separation of the WECC-connected interties during high import conditions. The purpose of LSSi is to arrest the frequency decline resulting from the controlled separation and prevent the under-frequency load shed program from operating and tripping load.¹⁸¹

365. The AESO submitted that:

LSSi costs are derived from three components: an availability component, an arming component, and a tripping component. Costs are calculated based on actual volume amounts, with the exception of the arming component which also has a minimum guaranteed payment should arming levels fall below a threshold level. For all contracts, the availability payment is set at \$5/MWh and the tripping payment is set at \$1,000/MWh. Arming payments are unique to each provider. Loads are armed in order from lowest cost to highest cost.¹⁸²

Total cost for LSSi in an hour is determined as the sum of the availability payments, arming payments, and tripping payments in that hour.¹⁸³

5.6.2 AESO tariff application

366. The AESO's 2013 forecast of ancillary services costs includes \$68.7 million for LSSi¹⁸⁴ and proposed to include the cost of LSSi in the hourly allocation methodology of the operating reserve charge.¹⁸⁵

367. The AESO submitted that allocating LSSi costs hourly to market participants aligns with cost causation because hourly LSSi costs reflect LSSi volumes contracted to ensure reliable supply to load in an hour. As well, in as much as LSSi may potentially affect the energy market,

¹⁸⁰ Exhibit No. 109.1, AESO response to IRs, September 30, 2013, AUC-AESO-027, page 1, response (a).

¹⁸¹ Exhibit No. 109.1, AESO response to IRs, September 30, 2013, AUC-AESO-027, page 2, response (c).

¹⁸² Exhibit No. 109.1, AESO response to IRs, September 30, 2013, AUC-AESO-027, page 2, response (d).

¹⁸³ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, paragraph 264.

¹⁸⁴ Exhibit No. 2, AESO tariff application, July 17, 2013, page 9, paragraph 38.

¹⁸⁵ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, paragraph 263.

hourly allocation of costs will correlate to effects on the hourly energy market such that load market participants will be subject to both LSSi costs and related energy market effects in the same hours.¹⁸⁶ In addition, allocating LSSi costs hourly will minimize variances between LSSi costs and revenues that would otherwise require collection or refund through deferral accounts because LSSi costs are difficult to forecast.¹⁸⁷

368. The AESO proposed that LSSi costs be included with operating reserve costs and allocated hourly to market participants in demand transmission service rate (DTS) and Fort Nelson demand transmission service rate (FTS) in the tariff filed in Appendix L of the application.¹⁸⁸

5.6.3 LSSi defined as an ancillary service

369. The AESO submitted that LSSi is an ancillary service that is designed to provide frequency control to the interconnected electric system and is consistent both in form and substance with the definition of an ancillary service under the *Electric Utilities Act*. The AESO further submitted that it has an obligation under Section 16 of the *Transmission Regulation* to restore the interties to their path rating, and this obligation is what precipitated the development and procurement of LSSi. The AESO also stated that when additional intertie capacity is utilized, it creates a frequency control issue on the system which is managed by LSSi. That is, the interconnected electric system can only operate to a “satisfactory level of service” when LSSi is available and armed.¹⁸⁹

370. In addition to its obligation to restore the interties, the AESO submitted that it must plan a transmission system that is sufficiently robust so that 100 per cent of the time, transmission of all anticipated in-merit electric energy, which includes scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, can occur when all transmission facilities are in service.

371. In summary, the AESO submitted that LSSi is required: (1) to provide transmission capacity for import flows to the rated capacity of the interties, and, (2) to provide system support when additional transmission capacity for import flows is utilized. The AESO submitted that LSSi is an ancillary service, the costs of which have been approved by the ISO members as required by Section 48 (1) of the *Transmission Regulation*, and are appropriately allocated to load customers as costs of the transmission system.¹⁹⁰

372. Each of the ADC, the CCA, EnerNOC and the UCA agreed with the AESO that LSSi was an ancillary service. The ADC supported the AESO’s rate structure for LSSi, and stated that the AESO has properly recognized and is using this as an ancillary service to ensure adequate service quality.¹⁹¹ The CCA submitted that by virtue of the requirement under the *Transmission Regulation* to restore tie line capacity to its path rating, it is clear that the cost of LSSi is an ancillary service.¹⁹² EnerNOC submitted that the definition of ancillary services is very broad, as

¹⁸⁶ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, paragraph 266.

¹⁸⁷ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, paragraph 267.

¹⁸⁸ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, at paragraph 268.

¹⁸⁹ Exhibit No. 264.02, AESO rebuttal evidence, January 20, 2014, PDF page 5, paragraph 12.

¹⁹⁰ Exhibit No. 264.02, AESO rebuttal evidence, January 20, 2014, PDF page 5, paragraph 13.

¹⁹¹ Exhibit No. 358.01, ADC argument, March 19, 2014, paragraph 5.

¹⁹² Exhibit No. 371.02, CCA argument, March 19, 2014, page 37, paragraph 101.

it operates in many jurisdictions, and the technical definition of ancillary services does vary across jurisdictions.¹⁹³ The UCA submitted that LSSi should be considered an ancillary service, similar to the past treatment of ILRAS and LSS.¹⁹⁴

373. ATCO Power, however, asserted a different view. It stated the inclusion of the word “required” in the ancillary services definition found in the *Electric Utilities Act*, means that ancillary services are not merely services that support the reliable operation of the AIES, or that could be helpful, they have to be required. That is, without the ancillary service, it must be impossible to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.¹⁹⁵

374. ATCO Power indicated that LSSi could sometimes be used as an ancillary service and sometimes not.¹⁹⁶ To the extent that LSSi is used in-market to enable imports, ATCO Power’s position was that LSSi was not an ancillary service. To the extent that LSSi could be used out-of-market to provide emergency power, LSSi could be an ancillary service.¹⁹⁷ Further, if all load was being served without LSSi being armed, then using LSSi to increase imports is a choice, not a requirement.¹⁹⁸ As the AESO cannot expect to have any particular amount of LSSi available in any given hour and has no means to compel the provision of LSSi, the AESO does not actually “require” LSSi and as such, LSSi does not meet the definition of “ancillary services” under Section 1(1)(b) of the *Electric Utilities Act*.

375. ATCO Power also provided its interpretation of further words used in the definition, including whether the “level of service” is “satisfactory” at the import levels that require no LSSi. ATCO Power stated that if it is, LSSi is not an ancillary service; if it is not, then LSSi is an ancillary service.¹⁹⁹ ATCO Power concluded that since LSSi is not required to provide a satisfactory level of service, it is not an ancillary service as defined in the *Electric Utilities Act*.²⁰⁰

376. ATCO Power also rejected the assertion that LSSi is required to satisfy the inertia restoration obligations required by Section 16 of the *Transmission Regulation*. ATCO Power submitted that the AESO’s legislative obligation to restore the inertias does not make LSSi a required product to provide a satisfactory level of service. In ATCO Power’s view, the consideration of whether LSSi is required to satisfy Section 16 of the *Transmission Regulation*, is separate from the consideration of whether LSSi is required to ensure that the AIES is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.²⁰¹

¹⁹³ Transcript, Volume 4, January 30, 2014, page 652, lines 8-20.

¹⁹⁴ Exhibit No. 364.02, UCA argument, March 19, 2014, page 15, paragraph 80.

¹⁹⁵ Exhibit No. 370.02, ATCO Power argument, March 19, 2014, PDF page 16, paragraph 72.

¹⁹⁶ Transcript, Volume 5, January 31, 2014, page 772, lines 2-5.

¹⁹⁷ Transcript, Volume 5, January 31, 2014, page 770, lines 17-23.

¹⁹⁸ Transcript, Volume 6, February 2, 2014, page 803, lines 6-14.

¹⁹⁹ Exhibit No. 370.02, ATCO Power argument, March 19, 2014, PDF page 16, paragraph 74.

²⁰⁰ Exhibit No. 155.02, ATCO Power evidence, December 5, 2013, PDF page 11, paragraph 42.

²⁰¹ Exhibit No. 370.02, ATCO Power argument, March 19, 2014, PDF page 18, paragraph 87.

Commission findings

377. Section 1(1)(b) of the *Electric Utilities Act* defines an ancillary service as follows:

“ancillary services” means those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency;

378. The position of ATCO Power, in its interpretation of this definition, is that an ancillary service can only be such if it is “required.” While ATCO Power concedes that there may be times, such as when LSSi could be used out-of-market to provide emergency power through imports, then LSSi could be an ancillary service; if there is a choice to be made regarding whether LSSi should be used, then it cannot be required and is not an ancillary service.

379. As noted in *Sullivan on the Construction of Statutes*, Fifth Edition, at page 359:

... when words are read in their immediate context, the reader forms an initial impression of their meaning. ... But any impression based on immediate context must be supplemented by considering the rest of the Act, including the other provisions of the Act and its various components.

Further, at page 364, the author notes:

When analyzing the scheme of the Act, the court tries to discover how the provision or parts of the Act work together to give effect to a plausible and coherent plan. It then considers how the provision to be interpreted can be understood in terms of that plan. ... The fundamental presumption in scheme analysis is being able to grasp and explain the basic structure on which the Act is built and how the various parts and provisions were meant to function within this structure to achieve the desired goal, or more often, the desired mix of goals.

380. The definition of ancillary services includes language that defines such a service as one that is “required.” However, the definition of ancillary services does not explicitly specify a limitation as to when or how often that service must be required before it is considered an ancillary service. In defining an ancillary service, these two requirements restrict the purpose of the service. Moreover, the word “required” is used in relation to the service provided. It must also be a service required to (1) ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service, which, in turn, includes (2) acceptable levels of voltage and frequency. An ancillary service is required to satisfy these requirements and not others. That is the sense in which “required” is being used.

381. In the context of ascertaining what was intended regarding “a satisfactory level of service,” a review of the *Electric Utilities Act* and the *Transmission Regulation* reveals that the act and regulation impose certain duties and obligations on the AESO to operate the interconnected electric system. For example, Section 17(a) of the *Electric Utilities Act* imposes a duty on the AESO to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy while Section 17(b) of the *Electric Utilities Act* requires the AESO to facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so. Additionally, Section 15 of the *Transmission Regulation* compels the AESO to plan a non-congested system, Section 16 of the

Transmission Regulation obligates the AESO to prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to its path rating and Section 17 of the *Transmission Regulation* requires the AESO to “make rules and establish practices respecting the operation of the transmission system and the management of transmission constraints that may occur from time to time.”

382. These provisions demonstrate an underlying obligation on the AESO to create a transmission operating environment in which service is unfettered, recognizing that constraints can occur from time to time. That is, arguably, the satisfactory level of service that is contemplated in the legislative scheme.

383. It is the evidence of the AESO that, operationally, in conditions where less than 450 MW is imported over the interties, the AIES can function reliably without LSSi being used.²⁰² In these conditions, LSSi is not required to ensure a satisfactory level of service with acceptable levels of voltage and frequency. When greater than 450 MW is imported over the interties, then LSSi is used to prevent frequency and voltage declines, and the service is required in order to provide a satisfactory level of service with acceptable level of voltage and frequency.

384. The Commission finds that the role of LSSi in increasing capability over the interties supports that legislative scheme to provide the satisfactory level of service contemplated by the act and regulation.

385. For these reasons, the Commission finds that LSSi meets the definition of an ancillary service.

5.6.4 Allocation of LSSi costs

386. The AESO submitted that allocating LSSi costs hourly to market participants aligns with cost causation because hourly LSSi costs reflect LSSi volumes contracted to ensure reliable supply to load in an hour.²⁰³ Moreover, as LSSi is an ancillary service, LSSi costs must be wholly charged to load market participants in accordance with Section 47 of the *Transmission Regulation*.²⁰⁴

387. The ADC submitted that it supports the AESO’s proposed pricing structure and opposed any proposed modification to the LSSi program including reassigning the cost allocation away from DTS customers.²⁰⁵ The ADC further supported the AESO’s allocation of the cost of LSSi in the operating reserve charge component of the DTS tariff. The ADC submitted that this component provides for hourly pro rata allocation of operating reserve charges allocated to the DTS load that was on the system at the time the cost was incurred, and by including the cost in this tariff component, it further reduced any Rider C effects that may arise out of inaccurate LSSi cost forecasts.²⁰⁶

388. EnerNOC submitted that load is the primary beneficiary of the LSSi program and supported the general principle that the costs associated with restoring import capability should

²⁰² Transcript, Volume 3, January 29, 2014, page 444, lines 22-25, and page 445, lines 1-7.

²⁰³ Exhibit No. 2, AESO tariff application, July 17, 2013, page 48, paragraph 266.

²⁰⁴ Exhibit No. 366.01, AESO argument, March 19, 2014, page 54, paragraph 182.

²⁰⁵ Exhibit No. 358.01, ADC argument, March 19, 2014, paragraph 5.

²⁰⁶ Exhibit No. 358.01, ADC argument, March 19, 2014, page 19.

be charged to loads, since loads benefit most from the additional capability, additional grid reliability and a stronger competitive wholesale electric market.²⁰⁷

389. TCE took no position regarding the allocation of LSSi costs but did argue that should the Commission determine that Rate IOS is inappropriately subsidized, and that importers should pay LSSi costs, further consultation is required and the Commission should not make a determination in this proceeding on how LSSi costs should be allocated.²⁰⁸

390. The CCA submitted that restoring tie line capacity beyond about 450 MW serves as the primary mechanism for opportunity imports. The CCA further submitted that if there are no opportunity imports, there would be no purpose in restoring tie line capacity beyond 450 MW, and this reasoning suggests the cost causation for LSSi is opportunity imports. The CCA's view argued that based on cost causation principles, the cost of LSSi should be allocated and recovered exclusively from IOS service customers.²⁰⁹

391. ATCO Power also argued that LSSi costs should be recovered from Rate IOS customers. It submitted that the sole purpose of LSSi is to increase the transmission capacity available to import opportunity customers. ATCO Power noted that the Commission's predecessor the EUB stated on page 86 of Decision 2007-106²¹⁰ that opportunity service "should be priced at no less than incremental variable cost of providing the opportunity service." ATCO Power submitted that Rate IOS customers should bear the cost of the service, and the AESO's proposed tariff is therefore unduly preferential and unjustly discriminatory, and not just and reasonable, in contravention of Section 121(2) of the *Electric Utilities Act*.²¹¹

392. ATCO Power submitted that LSSi is the AESO's method for making incremental transmission capacity available to imports, and importers can acquire system access service only under an opportunity service, namely Rate IOS. ATCO Power's view is that therefore Rate IOS customers are the only users and beneficiaries of the incremental transmission capacity.²¹² ATCO Power further submitted that the only proper way to allocate LSSi costs is to allocate them to Rate IOS customers; allocating the costs to consumers, amounts to nothing less than a cross subsidy.²¹³

393. ATCO Power submitted that if the only thing importers receive is an additional opportunity to access the Alberta market during normal market conditions, for example more or less the effect of the current LSSi program, then the restoration costs should be charged to the opportunity service customers.²¹⁴

394. ATCO Power submitted that arming costs are directly related to additional imports in real time and occur if and only if additional imports are flowing and, as such, arming payments are indeed an incremental variable cost of providing the service. ATCO Power indicated that while it might be debatable how the remaining costs of LSSi are allocated and recovered, including the

²⁰⁷ Exhibit No. 368.02, EnerNOC argument, March 19, 2014, page 6, paragraph 14.

²⁰⁸ Exhibit No. 360.02, TCE argument, March 19, 2014, paragraph 4.

²⁰⁹ Exhibit No. 371.02, CCA argument, March 19, 2014, page 38, paragraph 102.

²¹⁰ Decision 2007-106: AESO 2007 General Tariff Application, Application No. 1485517, December 21, 2007.

²¹¹ Exhibit No. 155.02, ATCO Power evidence, December 5, 2013, PDF page 4, paragraph 6.

²¹² Exhibit No. 370.02, ATCO Power argument, March 19, 2014, paragraph 92.

²¹³ Exhibit No. 155.02, ATCO Power evidence, December 5, 2013, PDF page 17, paragraph 73.

²¹⁴ Exhibit No. 239.02, ATCO Power IR response to AESO, January 10, 2014, PDF page 7.

arming costs in Rate IOS and instead allocating it to DTS customers amounts to a cross subsidy in favour of customers receiving service under Rate IOS.

Commission findings

395. As an ancillary service, LSSi costs are approved by ISO members and the AESO has indicated that the ISO members have approved such costs.

396. Section 20 of the *Electric Utilities Act* empowers the AESO to make rules respecting the provision of ancillary services. However, the language is permissive and, therefore, there is no obligation on the AESO to create a rule for LSSi and currently, no such rule exists. As such, oversight of these costs is limited to the consultation process required between the AESO and market participants who are affected by such costs and the direction provided to the Commission pursuant to the legislation.

397. Section 48(2) of the *Transmission Regulation* states:

(2) When considering the ISO's own administrative costs under section 46 and the ISO's costs for the provision of ancillary services, the Commission must allocate to customer classes those amounts that are set out in the ISO's application to the Commission for approval of the ISO tariff.

398. Section 47 of the *Transmission Regulation* states:

47 When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Commission must

(a) ensure

(i) the just and reasonable costs of the transmission system are wholly charged to DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and ...

399. LSSi was developed by the AESO as a non-wires option to support its obligations under Section 16 of the *Transmission Regulation* which require the AESO to restore interties existing on August 12, 2014 to their path rating. To do this, LSSi facilitates incremental imports by ensuring system reliability when greater than approximately 450 MW is imported over the BC intertie.

400. The *Transmission Regulation* requires the Commission to ensure that any tariff that it approves recovers transmission system costs from load (customers). As LSSi is a cost of the transmission system, the Commission cannot approve a tariff that does not charge these costs to load customers. Rate IOS customers are not load customers. The Commission approves the allocation of LSSi costs as proposed by the AESO.

401. The Commission expects that the AESO will monitor the costs of LSSi such that these costs should not outweigh the benefits to the AIES and that both the AESO and the market participants, through the consultation process, will address this issue in that forum.²¹⁵

5.7 Bill effects

402. The AESO addressed the effects on market participants' bills of the rate DTS changes proposed in its application at Section 6.5 and Appendix I of the application. Section 6.5 provided a summary of the results of the bill effects. Appendix I provided the detailed analysis of the results.

403. The AESO reviewed past direction from the board regarding bill effects as part of its analysis. In Decision 2005-096, the board found that rate shock should be given secondary consideration as a rate design criterion and that, on balance, if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism. In Decision 2007-106, the board directed that bill effects be assessed against currently-approved rates and include all components of a bill including commodity costs.

404. The AESO explained that for this application, it had compared, on a per-point-of-delivery basis, bills under the proposed 2014 Rate DTS to bills under the 2013 Rate DTS presented in Section 4 of its application. The 2013 Rate DTS reflected the currently-approved 2011 Rate DTS plus amounts that would be collected or refunded through Rider C and deferral account reconciliations. Therefore, comparing bills under the proposed 2014 Rate DTS to bills under the 2013 Rate DTS most clearly illustrated the effect of changes to transmission cost functionalization and classification discussed in Section 5 of the application.

405. The bill effect analysis was based on an extract of actual market participant billing determinants for each rate DTS point of delivery from January 2010 to December 2012, including coincident metered demand, substation fraction, and actual pool price for metered energy at each point of delivery. For the comparison, the proposed 2014 Rate DTS and the 2013 Rate DTS were applied to the same billing determinants, including pool price, at each point of delivery. This approach isolated the increases attributable to rate DTS changes only.

406. The AESO stated the majority of rate DTS points of delivery (428, or about 82 per cent) received increases of ± 10 per cent based on rate DTS charges, rate PSC credits, and commodity costs. In addition:

- 49 points of delivery (about nine per cent of the total) received decreases from -10 per cent to -75 per cent
- 47 points of delivery (about nine per cent of the total) receive increases from +10 per cent to +60 per cent

407. Appendix I provided additional information on the 47 services receiving increases greater than 10 per cent due to the proposed 2014 Rate DTS. Of those services, 44 (about 94 per cent) are dual-use sites where services are provided under both rate DTS and rate STS.

²¹⁵ See Section 3(1) of the *Transmission Regulation* regarding the duty of the AESO to consult.

408. The AESO stated that the bill effects provided in Appendix I and summarized in Table 6-5 and Figure 6-6 resulted from rates based on cost causation as discussed in Section 6 of the application. Given the comments from past decisions regarding cost causation, bill effects, and dual-use sites, the AESO did not propose any rate modifications or additional rates or riders to mitigate bill effects arising from its proposed 2014 Rate DTS.

409. In its argument submission, the AESO noted that the DUC had proposed using 1.5 MW rather than 0.1 MW as the data point to determine the customer (fixed) and first demand tiers for the straight-line approximation of the point of delivery cost function. The effect of this revision resulted in more services receiving an average rate increase of zero per cent to 10 per cent.²¹⁶ The AESO did not accept the DUC's proposal and, regardless, argued that the DUC recommendation would not require rate mitigation even if the proposed change to the customer charge was accepted.

410. The AESO also noted that the DUC had proposed a portion of the demand-related regional system costs be collected through a demand-distance (MW/km) charge. The AESO was critical of this recommendation and suggested that the bill effects at load-only sites may be large enough to warrant further investigation and, potentially, mitigation.

411. The AESO noted the CCA had proposed a CP/85 per cent NCP method for recovering bulk system costs and provided estimates of the bill effects in its response to AUC-CCA-1²¹⁷ and in its responses to undertakings given to the ADC during the oral hearing.²¹⁸ The AESO stated the CCA estimated the transmission-only rate effect of its CP/85 per cent NCP method to range from about 20 per cent to 96 per cent for the hypothetical services considered. The AESO noted that these effects appeared to be relative to the 2014 rates proposed by the AESO rather than to the 2013 rates against which the AESO assessed bill effects. The CCA's estimated effects would, therefore, be additive to the bill effects calculated by the AESO. The AESO rejected the CCA proposal and submitted that the additional bill effects from the CCA's proposed CP/85 per cent NCP method were large enough to warrant further examination and, potentially, mitigation.

412. Finally, the AESO noted the UCA had proposed to use the average and excess method for classifying special projects costs and provided an estimate of the bill effect in its response to an undertaking given to Commission counsel during the oral hearing.²¹⁹ The AESO noted that the UCA analysis showed less than \pm one per cent effect on the average delivered costs of electricity for the example large industrial, small industrial, and residential customers, compared to the 2014 rates proposed by the AESO. The AESO submitted that the UCA's average and excess method should be rejected by the Commission but acknowledged that the additional bill effects from the UCA's proposal were small enough that measures to mitigate the bill effect would not be required.

413. The AESO was the only party to submit argument comment on the issue of bill effects.

²¹⁶ Exhibit No. 217.06, DUC revised evidence at page 21, Figure 7.

²¹⁷ Exhibit No. 216.01, AUC-CCA-1.

²¹⁸ Exhibit No. 329.01, CCA undertakings.

²¹⁹ Exhibit No. 328.01, UCA response to undertaking.

Commission findings

414. When the AESO files its compliance filing, the Commission will consider the bill effects resulting from its findings in this decision with respect to rate design and will consider whether it is necessary to address any mitigation measures in that proceeding.

5.8 Long-term transmission rate impact projection

415. The AESO provided detailed rate calculations for 2014 in its application. In addition, the AESO included as Appendix J to the application a projection of transmission costs and rate DTS to 2031. The transmission rate impact projection workbook provided context for changes to rate DTS over the period covered by the AESO's most recent long-term transmission plan. The rate impact projection incorporated the most recent information available as of early 2013 and allowed assumptions to be varied to test the sensitivity of the projection to changes in those assumptions. The rate impact projection also allowed example billing determinants to be varied to provide a projection of specific bills for individual load characteristics.

416. The AESO explained the transmission rate impact projection assumed the functionalization and classification of transmission costs continued into the future as proposed in this application for 2016. The rate impact projection also assumed:

- the design and structure of rate DTS will continue unchanged from the proposals in this application
- the allocation of transmission costs to residential consumers through the tariffs of distribution system owners will maintain currently-approved approaches, allocations, and structures

417. The AESO stated that while it was not seeking approval of the transmission rate impact projection, the AESO considered the projection to offer useful context in which to review the rate changes proposed in this application. The AESO considered the proposed rate changes to be aligned with long-term transmission cost trends.

418. The AESO provided an update to Appendix J in accordance with the NSA. The revised workbook provided a projection of transmission costs and rate DTS to 2033 as context for changes to rate DTS over the period covered by the AESO's most recent long-term transmission plan. The rate impact projection incorporated the most recent information available as of December 2013 and allowed assumptions to be varied to test the sensitivity of the projection to changes in those assumptions. The rate impact projection also allowed example billing determinants to be varied to provide a projection of specific bills for individual load characteristics.

419. The AESO stated that it was not requesting approval of the transmission rate impact projection in this proceeding. Rather, the rate impact projection was provided for information purposes (i) in response to Commission comments in Decision 2010-606 respecting the AESO's 2010 tariff application; (ii) in response to stakeholder requests for such a projection; and (iii) as additional analysis related to the AESO's periodic filing of its long-term transmission plan. The AESO noted that no party objected to the AESO's inclusion of the transmission rate impact projection in the Application, and some parties used the rate impact projection to inform their

analyses and evidence. For example, the UCA used the rate impact projection in assessing the impact of its proposed average and excess method for classifying special projects costs.²²⁰

420. In their argument, the ADC supported the AESO continuing to update and publish a long-term transmission rate impact projection model at least once a year.

421. The DUC also supported the AESO continuing to update and publish the long-term transmission rate impact projection model at least once per year and stated that its members found the rate impact projection model to be a useful tool to help them manage and plan for the significant rate increases that have occurred and are forecast.

Commission findings

422. The Commission finds the AESO's current practice to be helpful and the AESO is therefore directed to continue its current practice of providing its long-term transmission rate projections.

6 Terms and conditions

6.1 Cochin substation matters

423. FortisAlberta Inc. (Fortis) identified an issue arising from changes to the electric services provided to an end-use customer served through the Cochin 968S substation in information requests.²²¹ The Cochin 968S substation is located near Wainwright, Alberta.

424. In its preamble to information request FAI-AESO-001, Fortis explained that:

- it contracts for system access service with the AESO at the Cochin substation on behalf of a transmission-connected end-use load customer that is served under Rate 65 of the Fortis tariff
- Fortis' contract capacity with the AESO at the Cochin substation is 1.9 MW
- the AESO and Fortis both have the understanding that there is no expectation of substantial load growth at the Cochin substation in the foreseeable future.

425. Fortis further noted in its preamble to FAI-AESO-001 that, as part of the Central East Region Transmission Development project, the AESO had considered the following three primary options to provide the continuation of service to the end-use customer:

- Option 1: The installation of a 138/69-kV transformer at Wainwright 51S as a new source for the 69-kV line to Cochin substation. The estimated cost of transmission system changes associated with this option was \$2.5 million.²²²
- Option 2: The conversion of the end-use customer's existing service to a 25-kV distribution connection, to be served under either FortisAlberta Rate 61 or Rate 63. Fortis explained that this option would require expenditures on FortisAlberta distribution

²²⁰ Exhibit No. 328.01, response to undertaking from Commission counsel.

²²¹ Exhibit No. 102.01.

²²² Exhibit No. 201.02, Fortis noted in the preamble that the estimated costs of each of the three options is stated in 2013 dollars.

system changes of \$0.5 million (for construction of 3.2 km of distribution line) and expenditure of \$0.7 million by the end-use customer to install a variable frequency drive, for a total estimated cost of \$1.2 million.

- Option 3: Rebuilding the existing 61L 69-kV line that is currently planned to be removed, to allow the continuation of 69-kV service to the end-use customer through the Cochin substation. Fortis noted that as the 69-kV facilities are approaching the end of their service life, rebuilding of the 69-kV facilities would have to occur in the near future. Fortis noted that the estimated cost of Option 3 is \$9 million.

426. In its intervenor evidence,²²³ Fortis explained that, for reasons of system development, the 69-kV facilities currently serving the Kinder Morgan Fabyan pump station at POD 968S will be removed. Further, Fortis explained that the proposed Option 2, which would require the construction of new 25-kV facilities to serve the Kinder Morgan load and the transitioning of Kinder Morgan to the General Service Rate 61 under the FortisAlberta distribution tariff, is the least expensive option when both transmission and distribution facility costs are considered. As such, Fortis submitted that the Option 2 approach was likely to be adopted as the Central East Region Development project moved forward.

427. Fortis stated that although it expects that any costs it prudently incurs in conjunction with the Central East Region Development project will be reflected in its tariff in due course, the Central East Region Development project gives rise to costs that Kinder Morgan should not, in fairness, be required to bear.²²⁴ Therefore, Fortis proposed that the prudent costs incurred by Kinder Morgan to conform their facilities to reflect the effect of the transmission system development be treated as part of the cost of the transmission system development.

428. Fortis noted that in its responses to Fortis' information requests, the AESO:

- did not agree with the Fortis proposal to treat the end-user's costs as the cost of the transmission system development²²⁵
- proposed that the matter be pursued through the dispute resolution provisions under its tariff
- appeared to agree that, with the approval of the Commission, the costs in question could be treated as either a negative transmission contribution or a contribution refund under the AESO's tariff.²²⁶

429. At the close of its intervenor evidence, Fortis explained that its "bottom line" request is that, in the particular circumstances of the effects of the AESO's Central East Region Development project on service to the Kinder Morgan Fabyan pump station, the Commission should direct the AESO to treat the prudent costs incurred by Kinder Morgan to install a variable frequency drive as part of the costs of the project, to be implemented either through a negative contribution or a contribution refund.

²²³ Exhibit No. 144.02.

²²⁴ Exhibit No. 144.02, paragraph 6. Fortis also noted that Kinder Morgan's concerns were outlined in a letter dated November 21, 2013, attached to its evidence.

²²⁵ Exhibit No. 102.01, FAI-AESO-001(k), FAI-AESO-002(a)(b), and FAI-AESO-003.

²²⁶ Exhibit No. 102.01, FAI-AESO-002(g) and (h).

430. In its rebuttal evidence, the AESO noted that Fortis' response to AESO-FAI-002(d)²²⁷ suggests that the selection of Option 2 for system expansion creates a system benefit for all Alberta transmission customers while imposing costs on the distribution company, its customers, and the end-use customer in question. However, the AESO submitted that this characterization is not complete, since Fortis' response to AESO-FAI-001²²⁸ indicates that charges to Kinder Morgan will decrease from about \$30,000 per month to about \$20,000 per month as a result of the proposed changes.

431. Given the difficulty of precisely accounting for costs and benefits on both the shared transmission system and shared distribution system, the AESO submitted that it had proposed a reasonable approach whereby costs of transmission facilities and distribution systems are born by the transmission facility owners and distribution system owners, respectively. Further, the AESO submitted that in instances where parties have agreed on the preferred options, consistently treating costs as it has proposed will result, on average, in a reasonable and equitable sharing of costs and benefits by all affected parties.

432. In argument, the AESO summarized its understanding of Fortis concerns, as set out in its response to FAI-AESO-001,²²⁹ and restated a view addressed in its response to FAI-AESO-001(k) that payment of costs related to market participant facilities downstream of the point of delivery is not consistent with Section 3(2) of Section 3 of its tariff terms and conditions. Further, the AESO noted that in its response to FAI-AESO-002(d),²³⁰ it had noted that Section 8.1 of FortisAlberta's current customer terms and conditions of electric distribution service contains comparable provisions regarding the end-use customer's responsibility for all required wiring and electrical equipment on the end-use customer's side of the point of service.

433. The AESO further noted that, as set out in its response to FAI-AESO-002(d), Fortis' current rates include the Customer Specific Facilities Rider E, which allows for the revenue requirement recovery of facilities on customer-owned or leased property.

434. The AESO noted that it explained during the oral hearing that it is rare to encounter circumstances similar to those arising in respect of the Cochin substation. As set out in its response to FAI-AESO-003, the AESO noted that recovery of the costs of facilities owned by a market participant or end-use customer requires the Commission's approval under Section 30(2)(a)(iv) of the *Electric Utilities Act*. As such, the AESO submitted that recovery of this nature should be addressed on a case-by-case basis rather than through a general tariff provision.

435. In summary, the AESO submitted that the issues to be addressed by the Commission are:

- whether relief should be provided to Kinder Morgan
- if relief should be provided, which party (Fortis or the AESO) should provide the relief

436. If the Commission finds that relief should be provided, the AESO considered that either the AESO or Fortis could be directed to provide the relief.

²²⁷ Exhibit No. 201.02.

²²⁸ Exhibit No. 201.02.

²²⁹ Exhibit No. 366.01, AESO argument, paragraph 205.

²³⁰ Exhibit No. 102.01.

437. In its argument, Fortis restated its bottom line request that the Commission direct the AESO to treat Kinder Morgan's prudent cost of installing a variable frequency drive as part of the cost of the Central East Region Development project, either through a negative contribution or a contribution refund. Fortis provided a summary of the principle facts in support of this request, as set out in its evidence or in information requests.

438. Fortis noted that while the AESO does not support its proposal, the AESO has, nevertheless, recognized that the costs in question could be recovered in various ways, contingent on the approval of the Commission.²³¹ Fortis also noted that such acknowledgment was provided by the AESO in discussion with Commission counsel.²³²

439. Fortis noted that it had agreed during questioning by Commission counsel that costs incurred by Kinder Morgan could be paid by FortisAlberta and recovered through its tariff, rather than the AESO's.²³³ However, Fortis submitted that as transmission system development is the driver of Kinder Morgan's costs in this case, and as benefits accrue to the overall transmission system, it remains Fortis' belief that recovery of these costs through the AESO's tariff is the more apt approach.

440. In reply argument, the AESO agreed with the facts as summarized in Fortis' argument but did not otherwise add to its argument submission.

441. In its reply argument, Fortis submitted that while the AESO makes a passing reference to the existence of Rider E within the approved Fortis tariff, this provision should play no part in the current proceeding, since there is no proposal by either Fortis or Kinder Morgan for Rider E to be applied in the circumstances of the Cochin substation. In any event, Fortis submitted that while Rider E would permit costs to be recovered over time rather than up front, this does not address the concern about inappropriately requiring a customer to pay for the cost of a variable frequency drive to accommodate AESO transmission system development.

442. Fortis submitted that the AESO's suggestion in argument that Kinder Morgan charges for electricity service are likely to drop as a result of the proposed changes to service is somewhat misleading, since it is clear from the record that the Cochin 986S substation currently at the end-use customer's doorstep is to be entirely removed. Given that the changes in service will require Kinder Morgan to share system access service with other customers from a more distant POD and take service at lower voltage, Fortis submitted that the reduction in tariff charges should be considered to be commensurate with the reduction in the level of service Kinder Morgan will receive, and not a benefit *per se*.

443. Fortis indicated that it agreed with the AESO's observation that it is open to the Commission under Section 30(2)(a)(iv) of the *Electric Utilities Act* to allow the AESO to recover "... any other prudent costs the Commission considers appropriate" and as the transmission system development is the underlying reason that Kinder Morgan facilities will be rendered inoperative, the appropriate remedy is through the AESO tariff.

²³¹ Exhibit No. 102.01, FAI-AESO-002(g) and (h).

²³² Transcript, Volume 3, page 411.

²³³ Transcript, Volume 7, pages 988-989.

Commission findings

444. Fortis has taken the position that Kinder Morgan should be compensated if it is required to bear a material incremental cost as a result of a potential change from a 69-kV transmission service to a 25-kV distribution service, because the change in service has been driven by a decision of the AESO to reconfigure the transmission system in that area.

445. The evidence reveals that the change in the facilities used to provide electrical service to the Kinder Morgan Fabyan pumping station arises from an assessment carried out within the context of a comprehensive regional system plan, the Central East Regional Development program. Any decision to remove the Cochin substation and related facilities and to provide service to Kinder Morgan at the Fabyan pumping station through a 25-kV distribution connection would represent the reasonable outcome of the development and review of the Central East project under consideration in the NID and facility applications before the Commission.

446. The record reveals that the 69-kV facilities, including the Cochin substation, are considered to be at the point where material capital replacement and upgrade expenditures on the 69-kV facilities would have to be made if the facilities were to be kept in active service.²³⁴ The options presented were to install a new transformer to support the existing 69-kV line, at an estimated transmission cost of \$2.5 million, conversion of the end-use customer's existing service to a 25-kV distribution connection at a total estimated distribution cost of \$1.2 million (\$0.5 million for construction of 3.2 km of distribution line and \$0.7 million by the end-use customer to install a variable frequency drive) or rebuilding the existing 61L 69-kV line that is currently planned to be removed, to allow the continuation of 69-kV service to the end-use customer through the Cochin substation at a transmission cost of \$9 million.²³⁵ In those circumstances, it is incumbent on both the AESO and on Fortis, to make reasonable decisions on the configuration of transmission and distribution facilities that would reliably serve both current and anticipated future end-use customers at the lowest overall cost. The lowest overall cost, as presented in this proceeding, is to convert the service from transmission service to distribution service.

447. The evidence on this record also shows that, as a result of the reconfiguration, charges to Kinder Morgan will decrease from about \$30,000 per month to about \$20,000 per month as a result of the proposed changes. Fortis has argued that this reduction should be considered as compensation for receiving a shared service. However, there is no evidence on the record to indicate that serving the customer at a distribution level will be at a reduced level of reliability or service quality. If that is the case, this is a matter for Fortis, as the distribution utility, to resolve with its customer.

448. The Commission agrees with the AESO's position that any additional variable frequency drive equipment that may be required as a result of a change to 25-kV service cannot be considered to be a transmission facility for the purposes of Section 1(1)(bbb) of the *Electric Utilities Act*. As such, the only mechanism that would be open for the recovery of "behind the fence" costs that may be incurred by Kinder Morgan would be through Section 30(2)(a)(iv) of

²³⁴ Exhibit No. 102.01, Fortis' description of Option 3 in preamble to FAI-AESO-001 indicates that existing facilities are approaching the end of their service life.

²³⁵ Exhibit No. 102.01, FAI-AESO-002(g) and (h).

the *Electric Utilities Act*. The Commission does not find it to be reasonable under these circumstances to recover, what are clearly distribution costs, through the transmission tariff.

449. The Commission has previously determined in a prior AESO tariff proceeding that a requirement to install a variable frequency drive that may be required by a specific distribution system owner is a matter for consideration within the context of the distribution system owner's tariff terms and conditions.²³⁶ As it is the relationship between Fortis and its customer that requires the installation of the variable frequency drive, Fortis is likewise in the best position to determine whether the cost of such a facility should be paid for by its customer under its tariff. Accordingly, Fortis' request is denied.

6.2 Classification of costs as system-related or participant-related

450. In Section 7.4.1 of the application, the AESO noted that its tariff includes provisions that define which costs of a connection project will be classified as participant -related and which will be classified as system-related. Participant-related costs are attributed directly to the connecting market participant and costs classified as system-related are shared with all market participants through Rate DTS.

451. The AESO proposed amendments to those provisions in its tariff to provide additional clarity and transparency with respect to the designation of participant-related and system-related costs. The proposed amendments are intended to provide consistency and predictability for market participants and to enable market participants and transmission facility owners to identify more readily participant-related and system-related costs during their preparation of connection proposals. The AESO stated that the proposed revisions provide additional detail that is not currently explicit in the tariff but which reflects its current practice.

452. The AESO proposed a number of changes to certain provisions in subsection 3(2) of Section 8 of its tariff terms and conditions²³⁷ including, in particular, the removal of subsection 3(2)(l) of Section 8, which reads as follows:

- (l) the advancement of transmission facilities included as part of a critical transmission development or regional transmission system project under subsection 3(3)(b) below, calculated as the difference between the present values of the capital costs of the advanced and the as-planned facilities using the discount rate provided in subsection 11 below;

453. In addition, the AESO proposed a revision to subsection 3(3) of Section 8 of its tariff terms and conditions for the purpose of clarifying that when a connection project involves an upgrade or expansion to existing transmission facilities that are classified as system-related, the costs of the upgrade or expansion would also be classified as system-related. The AESO indicated that its proposed change reflects its current cost classification practice. The AESO proposed to reflect this change in the following wording of Clause (d) of subsection 3(3):

- (3) The ISO must include as system-related those costs related to a connection project that are associated with:

²³⁶ Decision 2007-106, page 105.

²³⁷ Exhibit No. 26, application, paragraphs 359-364.

...

- (d) upgrades or expansions to existing **transmission facilities** which were previously classified as system-related and which will be utilized by multiple market participants ...

454. In its argument, the AESO noted that in cross-examination by Commission counsel, it explained that the timing of system-related facilities is determined in accordance with its mandate to develop a transmission system that allows load and generation market participants to connect. As such, when the timing of system-related facilities must be adjusted to facilitate those connections, it is fair and appropriate that the financial effect of such adjustments should also be generally considered to be system-related costs.

455. The AESO further submitted that as significant time and effort may be required to calculate the cost of system advancement and explain its effect to market participants, the changes to the terms and conditions proposed are reasonable, particularly in light of the fact that the actual application of advancement costs to market participants is rare. The AESO submitted that its proposed removal of the existing provisions dealing with the advancement of system costs should be approved as proposed and that its approach is consistent with its mandate to develop a transmission system that allows load and generators to connect in accordance with Section 15(1)(e) of the *Transmission Regulation*.

456. In its argument, the UCA opposed the AESO's proposal to remove the current provision in Section 8.3(3) of the AESO's terms and conditions that treats the costs of advancing system projects necessary to provide service to a new customer as a customer-related cost.

457. The UCA noted that customers connecting to the transmission system have very large loads. Given this, the UCA submitted that new customers should be expected to provide reasonable notice to the AESO and that other AESO customers should not be required to pay for any additional costs incurred to advance the construction of system facilities to provide service to a new customer that does not provide adequate notice. The UCA noted that a witness, on behalf of Devon, agreed that such advancement costs should be to the account of the customer.²³⁸

458. Further, the UCA argued that administrative convenience, which the AESO submitted as a benefit in support of its proposed amendment,²³⁹ should not be grounds for removing this provision from the AESO's terms and conditions.

Commission findings

459. The AESO's proposed revisions to its terms and conditions highlight a greater issue than simply providing clarity regarding the AESO's proposed classification of costs as system costs as set out in the application. Rather, the proposed revisions, which are reflective of the AESO's current practice, call into question, not only what costs should be treated as system costs, but also, as noted by the UCA, who should bear the incremental costs of system-projects that are accelerated to serve specific customer load.

²³⁸ Exhibit No. 364.02, UCA argument, paragraph 85 (references Transcript, Volume 6, pages 933-934).

²³⁹ Exhibit No. 364.02, UCA argument, paragraph 86 (references Transcript, Volume 3, page 398).

460. The Commission's findings in respect of participant-related and system-related costs are discussed under the following subheadings:

- the AESO's legislative duty to complete system projects
- the nature of the AESO's duty to set and achieve in-service targets for connecting loads
- upgrades or enhancement to system-related facilities used by multiple market participants

AESO's legislative duty to complete system projects

461. In AUC-AESO-036(b), the AESO was asked to explain why the public interest would be better served by eliminating the incentive in the current Section 8.3(2)(l) for market participants to take into account the incremental costs arising from the advancement of in-service dates.

462. The AESO's response is reproduced as follows:

The AESO is required to plan the transmission system to accommodate the connection of load and generation projects over time, in accordance with requirements of the *Electric Utilities Act*. In particular, the *Act* requires the AESO:

17(i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;

In addition, the *Transmission Regulation* requires the AESO to:

15(1)(e) ... plan a transmission system that (i) is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy ... can occur when all transmission facilities are in service

The public interest is served when the AESO meets its obligations under the *Act* and *Transmission Regulation*. Although the AESO may be unable [*sic*] anticipate the specific timing of projects with certainty when planning system projects, those system projects are responsive to the needs of market participants. The AESO considers that sufficient incentives exist in the remainder of the contribution policy in the tariff to ensure that market participants do not needlessly request system access service.²⁴⁰

463. The AESO's response to AUC-AESO-036(b) was pursued further through questions put to the AESO panel by Commission counsel. In that discussion, Commission counsel asked the AESO to discuss further Section 15(1)(e) of the *Transmission Regulation* and Section 17(i) of the *Electric Utilities Act*, and in particular, address potential differences in the application of these legislative provisions as applied to generation and load connections. This discussion is reproduced, in part, below:

Q: ...

Now, I'm always a little reluctant to ask questions about legislation, and I'm sensitive to the fact that I don't want legal answers, but the response does reference a couple of provisions. So I just want to explore a little bit at a high level your general views as to what you think those sections practically apply or how they practically apply to the AESO. So the language in Section 15(1)(e) of the transmission regulation appears to

²⁴⁰ Exhibit No. 109.01.

be primarily focused on setting out the AESO's duty to eliminate congestion and to provide guidance to the AESO to make arrangements for transmission expansion to accommodate anticipated generation projects. Is that a fair summary of how you would view that?

A. MS. KERR: Yes, it is.

Q. Thank you. Do you think that it would also apply to load -- connection -- sorry -- load connections?

A. MS. KERR: I think it primarily applies to generation. The IR itself I don't think was limiting itself to load.

Q. Sure. And I just gave you the IR as a place to start. So just generally, like setting aside your answer in the IR, I'm just wondering if you think that Section 15(1)(e) you could apply to load connection. So I'm thinking possibly if the load could -- that's connected could relieve congestion and maybe you would apply that section or that would seem reasonable to you?

A. MS. KERR: Yes, I believe that's correct.

Q. Thank you. So I'm great with the hypothetical. So here's another one. Suppose there's a customer that requires a connection to the transmission system to get service. And before that can happen, another new set of lines that's already been designated as a system-related line is in the planning process and that has to be completed and energized. And the situation I'm thinking about is in a new area. So we're not putting these lines into relieve congestion. In that circumstance, would the AESO consider that Section 15(1)(e) of the transmission regulation would apply to the AESO's obligation to complete the new transmission line project that's been designated as a system project by a specific date?

A. MS. KERR: I apologize. Just so I'm clear, are you referring to a generation project?

Q. I'm thinking of we've got a customer that needs to connect a load. I'm thinking load, not generation yet.

A. MS. KERR: Okay. So in that case, I think that the legislation is quoted in the answer to (b). 17(i) is probably where we would primary --

Q. So in the absence of a congestion situation, we're looking at 17?

A. MS. KERR: I think so, yes.

Q. The simple route?

A. MS. KERR: Yes.²⁴¹

464. The Commission agrees with the conclusion reached by the AESO in the above exchange that Section 17 of the *Electric Utilities Act* governs the AESO's duty to plan and arrange for

²⁴¹ Transcript, Volume 3, pages 377-380.

transmission enhancements necessary to accommodate loads where new transmission facilities are required.

465. Section 17 of the *Electric Utilities Act* sets out the duties of the AESO, and includes the following in clauses (i) and (j):

- (i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;
- (j) to make arrangements for the expansion of and enhancement to the transmission system;

466. The Commission considers that under clauses (i) and (j) of Section 17, the AESO has a duty to plan and arrange for new transmission facilities, but clauses (i) and (j) of Section 17 do not legislate any specific urgency to complete a transmission system project. Similarly, Section 33(1) of the *Electric Utilities Act* requires the “timely implementation of required transmission system expansions and enhancements” but leaves it to the AESO to determine what the timely implementation should be.

467. As well, the Commission also agrees that Section 15(1)(e) of the *Transmission Regulation* does not govern when the AESO must accommodate load connections, unless circumstances exist where the forecast load requires enhancements to the existing transmission system to eliminate any anticipated congestion. The Commission considers that when the driver for constructing facilities is the provision of service to a new load customer in an area that does not have existing transmission facilities and the new transmission facilities are to be designated as system-related (by virtue of considerations such as a looped configuration), then there would be no effect on system congestion. In these circumstances, there is no expectation of a potential benefit in the energy market from the relief of congestion.

468. Moreover, even in instances where sections 15(1)(e) and (f) of the *Transmission Regulation* govern, the legislative scheme does not impose a deadline by which the objectives in sections 15(1)(e) and (f) must be achieved. To the contrary, Section 15(2) of the *Transmission Regulation* provides for exceptions to the requirements set out in Section 15(1). These provisions recognize that it will take time to meet the requirements in Section 15(1) and that the AESO must have some ability to be relieved of its duties under sections 15(1)(e) and (f), on a temporary basis, so it is not in contravention of the legislation. Additionally, Section 15(3) of the *Transmission Regulation* authorizes the AESO to utilize a non-wires solution on either a permanent or interim basis. Further, Section 16 of the *Electric Utilities Act* imposes a duty on the AESO to exercise its power and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the transmission system and to promote a fair, efficient and openly competitive market for electricity.

469. Having considered the operation of all of these provisions, the Commission finds that the AESO has the responsibility to fairly and economically manage the timing for the construction of an uncongested system while the Commission has the overall authority to provide relief to the AESO in meeting this obligation through the Commission’s approval of exceptions pursuant to Section 15(2) of the *Transmission Regulation* and in the Commission’s authority to specify the period of time for which the exceptions would apply. Notably, the AESO has not exercised the discretion granted to it.

470. The Commission considers that the exercise of the AESO's discretion in the context of its duty to manage the timing for the construction of an uncongested system safely and economically is relevant to the Commission's assessment of whether, and to what extent, costs related to the advancement of system projects, driven at the request of a market participant, should be designated as a participant-related cost and paid for by the requesting market participant.

In-service targets and advancement of system projects

471. The Commission accepts the submission of the UCA that new customers requesting service should be expected to provide reasonable notice to the AESO and that other AESO customers should not be required to pay for any additional costs incurred as a result of the advancement of the construction of system facilities to provide service to a new customer that did not provide adequate notice.

472. The Commission takes note of the rationale for the proposed changes to the AESO's tariff provisions governing the classification of participant-related and system-related costs in the application:

361 This provision has been retained through several revisions of the AESO's tariff and was intended to charge advancement costs to a market participant when the schedule for a planned system development was accelerated to accommodate a new connection project for a market participant. However, the AESO plans the transmission system to accommodate the connection of load and generation projects over time. Although the AESO anticipates connection projects when developing its long-term transmission plan, the in-service dates of system developments ultimately accommodate the actual timing of connection projects. The appearance or delay of connection projects will accordingly affect the development of system projects. Since the system developments are ultimately responding to the need to connect market participant projects, it is inappropriate to assess costs to market participant due to the timing of their appearance.²⁴² [emphasis added]

473. The evidence on the record does not support the AESO's assertion that it is indifferent to the in-service demands of customers when planning its system requirements. There is persuasive evidence on the record of this proceeding that exceptional efforts to accommodate the desired timing of load connections may significantly contribute to the final cost of system projects. For example, during the oral hearing, Commission counsel discussed the circumstances of an actual radial load connection project that depended first on the completion of a planned looped system-related project, at least to the extent required to provide service to a substation on the planned looped project where the radial customer-related project was to connect.²⁴³ During the discussion of this project, the Commission observed that the AESO panel confirmed that the market participant requiring the radial connection intervened in the Commission proceeding assessing the TFO's request for a permit and license for a system-related project on the critical path for the receipt of electrical service.²⁴⁴ The AESO also agreed that this request was accommodated by the Commission through the Commission's consideration of a portion of the applied-for route several months in advance of the date that the Commission issued a decision on the TFO's full

²⁴² Exhibit 26, application, paragraph 361.

²⁴³ Transcript, Volume 3, pages 383-390.

²⁴⁴ Transcript, Volume 3, page 385 and Exhibit No. 281.

application.²⁴⁵ Notwithstanding these circumstances, the AESO confirmed that the market participant that requested the expedited approval of a portion of the looped system project was not considered by the AESO to have advanced the system project, because the market participant had not requested a change to the agreed upon date that the AESO had undertaken to commence electrical service at the point of delivery served by the radial connection.²⁴⁶

474. As discussed above, the AESO has a duty to carry out its responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the transmission system and to promote a fair, efficient and openly competitive market for electricity. This includes the discretion to target the completion of system projects in a timeframe that can be completed at a reasonable cost. The Commission recognizes that there may be other potential benefits associated with completing system-related projects for which timing of completion is primarily being driven by the need to accommodate a new customer's connection facilities (for example, the enhanced reliability that may be provided by "closing" a planned loop on a timely basis or the elimination or reduction of congestion on the system). However, the Commission considers that the benefits would only be associated with the incremental period that the facilities are advanced and, therefore, are likely to be small relative to the cost of advancement. The Commission expects that these benefits will be taken into account by the AESO when making decisions about the timing of transmission facilities to the extent that the benefit is reasonable in light of the associated cost.

475. On the basis of the foregoing, the Commission does not agree that subsection 3(3)(1) of Section 8 of the tariff terms and conditions should be deemed unnecessary and deleted. Moreover, in light of the consideration of the AESO's requested changes to system-related as compared to participant-related provisions in the tariff, the Commission considers that enhancements of these provisions may be necessary.

476. Accordingly, the Commission directs the AESO to redraft applicable elements of its terms and conditions to reflect the Commission's findings that the AESO has discretion to move a previously discussed in-service target date for a system project to a later date when a change in key assumptions underpinning the target date have materially changed. For example, if projected dates for the filing or approval of a needs identification document or facility application has materially changed, the AESO has the discretion to shift the target in-service date as well. For greater certainty, if the AESO has been advised by the TFO that the originally discussed in-service target for a system-related project cannot be met without the TFO materially increasing its project budget, the Commission expects that the AESO should consider a change to the in-service date it sets as a possible solution.

477. Conversely, the Commission considers that if a market participant requires a planned system project to be completed earlier than the in-service date and the AESO considers it to be reasonable in light of all relevant circumstances, this should be accommodated in the AESO tariff terms and conditions. However, in conjunction with this change, the AESO is directed to make it clear in its redraft of the relevant provisions that when a market participant elects to specify an in-service date earlier than the date the AESO had forecast for the system project that may be required as part of the requirements to connect the customer, including a subsequent

²⁴⁵ Transcript, Volume 3, page 386 and Exhibit No. 282.

²⁴⁶ Transcript, Volume 3, page 388.

revision of a target to a later date, the present discounted value of all the incremental costs and benefits as described in paragraph 474 above incurred in order to complete the system project by the requested date, rather than the initial target date will be deemed to be a participant-related cost for all purposes under the AESO's contribution policy.

478. The Commission considers this directed change to the terms and conditions to be reflective of the Commission's view that the provision of an efficient price signal is a key policy goal of the customer contribution policy.

479. The AESO is directed to provide its redraft of the applicable provisions discussed above in its refiling application pursuant to this decision.

Upgrades or expansions to facilities previously designated as system-related

480. The Commission understands that the proposed addition of subsection 3(3)(d) to Section 8 of the tariff terms and conditions is designed to reflect an apparent belief that once facilities are designated a system-related, any upgrade or expansion to those facilities should also be designated system-related if the upgrade or expanded facilities serve more than one market participant.

481. In considering this proposal, the Commission has taken into account that other provisions of the tariff terms and conditions would allow the cost of expansions and upgrades to be deemed system-related. However, for reasons discussed above in relation to the AESO's proposed elimination of subsection 3(2)(l), the Commission is concerned that where a market participant triggers the need for additional facilities ahead of the planned timeframe for such expansion, it is reasonable for the market participant to be responsible for additional costs. The Commission finds that treating such costs as system-related solely on the basis that the facilities are used by more than one market participant would have the effect of nullifying subsection 3(2)(l) and be contrary to the legislative regime outlined above.

482. Accordingly, the Commission denies the AESO's request to add subsection 3(3)(d) of Section 8 to its tariff terms and conditions. The AESO is directed to reflect this finding in its refiling.

6.3 Construction contribution policy

483. In Section 7.4.2 of the application, the AESO noted that on December 28, 2012, the Commission issued Decision 2012-362 in respect of the AESO's 2012 Construction Contribution Policy (2012 CCP) application. The AESO's 2012 CCP application had requested approval of:

- contribution policy principles
- a methodology for determining the POD cost function
- a methodology to determine maximum investment levels
- a proposal that its proposed investment levels should be made effective retroactive to July 1, 2012

484. On December 5, 2013, intervenor evidence in respect of the AESO's customer contribution policy was prepared by Depal Consulting Limited on behalf of Devon (the Devon evidence).²⁴⁷

485. In addition to the AESO, submissions on the AESO's contribution policy in argument or reply argument were received from Devon, AltaLink, the CCA, the UCA, and Enbridge.

486. The Commission has addressed the contribution issues identified in the submissions of the AESO and interested parties as follows:

- the effect of Decision 2012-362 on the manner in which the Commission should deal with contribution policy matters in the current proceeding
- contribution policy principles
- the level of investment coverage that should be targeted under the AESO's contribution policy, including issues related to the scope of the project cost dataset against which investment coverage is assessed
- the effective date for investment level changes
- the process for updating investment levels within tariff updates.

6.3.1 Effect of Decision 2012-362

487. AltaLink submitted that the AESO's recommendation to use an investment formula targeting average investment coverage of 60 per cent over all projects in the project represents a fundamental departure from what the AESO proposed in the 2012 CCP proceeding.

488. In its argument submission, AltaLink asserted that sufficient evidence to clearly establish the level at which investment can be considered excessive or insufficient was not provided in either the record of the 2012 CCP proceeding or in the current proceeding.²⁴⁸ Therefore, rather than approving the construction contribution policy proposed in the application, the Commission should reconstitute the working group engaged for the 2012 CCP for the purposes of developing an investment formula that:

- clearly establishes the level of investment that would not be considered either excessive or insufficient
- allows the agreed-upon level of investment to be achieved on actual projects under future AESO tariffs
- meets the three primary principles set out in Decision 2012-362

489. Once the above has been completed, AltaLink submitted that the AESO should bring its construction contribution policy back to the Commission for approval.

490. In the interim, AltaLink submitted that the Commission should approve a formula that will achieve, at a minimum, 60 per cent coverage when applied to new projects covered by the new tariff. Accordingly, AltaLink submitted that it supported the adoption of the proposals

²⁴⁷ Exhibit No. 146.02.

²⁴⁸ Exhibit No. 359.02, AltaLink argument, paragraph 6.

advanced by Devon as an interim solution while further work is being done by the AESO and its stakeholders.²⁴⁹

491. AltaLink indicated that its support of the Devon proposal on an interim basis reflected its disagreement with Devon that a 60 per cent coverage level ensures that intergenerational equity is maintained. In this regard, AltaLink noted that the Commission has not yet determined, in this or any other proceeding, the level at which investment should be considered excessive or insufficient. As such, AltaLink submitted that there is no basis on which to rule on the level of investment coverage that can be considered necessary to maintain intergenerational equity on a go-forward basis.²⁵⁰

492. AltaLink submitted that the Commission's ruling on the review and variance (R&V) application of Access Pipeline Inc. (Access R&V)²⁵¹ made it clear that the Commission expected that the AESO's proposed contribution policy and investment level recommendations should be supported by an evidentiary record that addressed the Commission's concerns raised in Decision 2012-362.²⁵²

493. While the AESO panel's testimony elicited from AltaLink's cross examination suggested that the Commission's findings in Decision 2012-362 amounted to a direction to base its investment level proposals on the achievement of 60 per cent project cost coverage,²⁵³ the fact that the Commission asked the AESO to explain why it proposed a 60 per cent coverage in AUC-AESO-019 in this proceeding suggests that the AESO was not directed to use the 60 per cent investment level but, rather, that this was a choice for the AESO to make.²⁵⁴

494. AltaLink submitted that Devon is incorrect to suggest that Decision 2012-362 established a framework for the construction contribution policy, including a "key" judgment that the decision set out that 60 per cent of aggregate connection costs should be covered by investment. Similarly, AltaLink noted the Commission expressed "concern" but did not specifically determine that 70 per cent coverage was either excessive or insufficient. Given this, and given the Commission's ruling in respect of the Access R&V, AltaLink submitted that it is clear that the Commission made no findings regarding investment levels in Decision 2012-362 and that this would be open to consideration in the AESO's next GTA.

495. In its argument, Devon submitted that issues relating to the AESO's proposed contribution policy were fully explored in the 2012 CCP proceeding.²⁵⁵ Devon submitted that in Decision 2012-362, the Commission considered principles germane to rate making and contribution policies, and commented in respect of these principles that it did not consider the principle of intergenerational equity to be sacrificed at the 60 per cent investment coverage level.²⁵⁶

²⁴⁹ Exhibit No. 359.02, AltaLink argument, paragraph 8.

²⁵⁰ Exhibit No. 359.02, AltaLink argument, paragraph 9.

²⁵¹ Exhibit No. 112.06.

²⁵² Exhibit No. 359.02, AltaLink argument paragraph 16.

²⁵³ Transcript, Volume 2, pages 192-193, referenced at paragraph 17 of AltaLink argument.

²⁵⁴ Exhibit No. 109.01.

²⁵⁵ Exhibit No. 361.02, Devon argument, paragraph 3.

²⁵⁶ Exhibit No. 361.02, Devon argument, paragraphs 4-5.

496. In reply argument, the AESO submitted that AltaLink's proposal to reconstitute the working group used for 2012 CCP consultations should be rejected. The AESO noted that members of the 2012 CCP working group supported the AESO's 2012 CCP application which was not approved by the Commission. The AESO also noted that the Commission made it clear in its March 11, 2013 response to the Access R&V application that the Commission was not prepared to make a decision on the contribution policy solely on the evidence that a number of parties found that the investment coverage the AESO had recommended to be acceptable.²⁵⁷

497. The AESO submitted that the current record was sufficient to allow the Commission to make a final determination on the AESO's contribution policy without a further application and proceeding. Further, the AESO submitted that the Commission should consider AltaLink's request for further process in light of the fact that AltaLink had the opportunity to file evidence in this proceeding on what it considered an appropriate contribution policy to be, but failed to do so.

498. In reply argument, AltaLink submitted that just as it is clear from Decision 2012-362 that evidence presented in the 2012 CCP proceeding was insufficient to allow the Commission to approve the AESO's proposal, the evidence in the current proceeding is similarly insufficient. As such, AltaLink submitted that the AESO must do further work on the CCP, with input from stakeholders, before filing it again for approval with the Commission.

499. AltaLink disagreed with Devon that construction contribution policy issues were fully examined in the 2012 CCP proceeding and that the AESO's proposals reflected a broad industry consensus. Although a comprehensive examination of contribution matters occurred in the 2012 CCP proceeding, the Commission nevertheless concluded that certain matters required additional deliberation before a proposal was brought back to the Commission for consideration in the AESO's next GTA. In AltaLink's view, the AESO's proposed contribution policy is materially different from the key consensus positions achieved within the 2012 CCP process which AltaLink stated were that:

- reasonable investment coverage falls in the range of 64 per cent to 76 per cent
- a 70 per cent target for investment levels
- only recent projects should be used to set the maximum investment level

500. AltaLink further rejected the AESO's suggestion that it reconvene the CCP working group and conduct additional consultation in response to Commission directions for further deliberation on certain aspects of its customer contribution policy. AltaLink argued that there is no evidence in the current proceeding that the CCP working group undertook substantial work or deliberation, and no evidence that the AESO's current proposals reflect a consensus. The AESO's response to a technical meeting question (TMQ-003), referred to in the AESO's argument, that purports to show how the AESO addressed Decision 2012-362 findings confirms that there is only a single limited mention of the 60 per cent investment coverage target in the Commission's findings.

²⁵⁷ Exhibit No. 112.06, paragraph 6.

501. Moreover, AltaLink submitted that the AESO's response to TMQ-003 reveals that the AESO made several key interpretations of Decision 2012-362 in preparing its CCP for the current application. Specifically:

- the AESO interpreted a single reference to 60 per cent as a direction to propose a 60 per cent target in the current proceeding
- the AESO interpreted Commission concern about moving away from the use of all projects to determine maximum investment levels as a direction to do so
- the AESO interpreted Commission concern that a 70 per cent target investment coverage and 64 to 76 per cent range "appear too high" as a direction to propose a customer contribution policy with a lower coverage and range

502. AltaLink submitted that the fact that the AESO shared its interpretation of Decision 2012-362 findings with stakeholders does not demonstrate that the AESO carried out further deliberation or evaluation of its customer contribution policy, as directed by the Commission in Decision 2012-362.

503. AltaLink disagreed with the AESO's suggestion in argument that certain interveners have attempted to re-argue matters previously rejected by the Commission. AltaLink submitted that this is not the case in respect of the AESO's construction contribution policy proposals, since Decision 2012-362 neither approved nor rejected the AESO's 2012 CCP application. In this regard, AltaLink submitted that the concerns set out in Decision 2012-362 have not been sufficiently addressed to allow a final determination of the AESO's current proposals, and in particular, the record of the current proceeding is not sufficient to identify the investment coverage level that is neither insufficient nor excessive. Accordingly, the Commission should reject the AESO's proposed customer contribution policy and grant the relief requested.

504. The UCA indicated that it strongly opposed AltaLink's suggestion to reconstitute the 2012 CCP working group. The UCA submitted that the 2012 CCP working group process was comprehensive and effective and, as no significant new issues have arisen since Decision 2012-362 was issued, reconstituting the working group would not add material value.²⁵⁸

Commission findings

505. While it is a central aspect of the Devon evidence that a 60 per cent investment coverage level should be considered to be a settled matter, AltaLink takes the position that Decision 2012-362 required the determination of a target investment coverage level that is neither excessive nor insufficient, but did not dictate that this level was 60 per cent and that the current proceeding did not address what percentage of coverage this requirement did represent.

506. The fact that the Commission did not make a ruling on a revised maximum investment function in Decision 2012-362 should not be interpreted to suggest that the Commission did not intend for parties to make recommendations for changes to the investment function in the course of the current proceeding.

507. Similarly, the Commission does not agree with the submission of AltaLink that the Commission's finding in respect of the Access R&V should be read to suggest that the

²⁵⁸ Exhibit No. 398.02, UCA reply, paragraph 46.

Commission did not intend for the AESO to provide submissions on recommended changes to its contribution policy in the current proceeding.

508. The Commission expected the AESO would take the findings in Decision 2012-362 into account when devising its customer contribution policy under its proposed tariff. Concerns expressed by the Commission in Decision 2012-362 included the following:

- that the AESO should not try to mitigate concerns about the level of TFO contribution in aid of construction balances through its contribution policy²⁵⁹
 - that changes to the average cost function should be applied simultaneously for both investment levels and establishment of Rate DTS²⁶⁰
 - that full consideration of the average POD cost function should take place in the AESO's next comprehensive GTA²⁶¹
 - that the AESO should consider changes to the inflation index used for contribution policy purposes in the next comprehensive tariff application²⁶²
 - that there be further deliberation on the proposed investment coverage level proposed in the 2012 CCP proceeding²⁶³
 - that the AESO take into account the Commission's finding that the "reasonable investment coverage range" of 64 per cent to 76 per cent proposed in the 2012 CCP application was too high, and required further evaluation²⁶⁴
 - that the AESO take into account the Commission's finding that the principle of intergenerational equity is not sacrificed at investment coverage levels of approximately 60 per cent²⁶⁵
 - that the AESO take into account the Commission's concern that increasing the level of investment coverage leads to unused investment which leads to increasing cost pressure and upward pressure on rates²⁶⁶
 - that the AESO should ensure that investment coverage levels achieve balance between the recognition of:
 - changes to service characteristics, functionality, and standards, and
 - increased costs due to:
 - increasing radial line requirements
 - increasing transmission voltage level
 - changing substation configurations
 - varying geography
 - unique construction and environmental conditions
- by regularly updating connection project data within general tariff applications.²⁶⁷

509. The Commission directed the AESO to bring forward a revised construction contribution policy that reflects the concerns expressed in Decision 2012-362 in its next comprehensive

²⁵⁹ Decision 2012-362, paragraph 81.

²⁶⁰ Decision 2012-362, paragraph 121.

²⁶¹ Decision 2012-362, paragraph 122.

²⁶² Decision 2012-362, paragraph 123.

²⁶³ Decision 2012-362, paragraph 178.

²⁶⁴ Decision 2012-362, paragraph 179.

²⁶⁵ Decision 2012-362, paragraph 180.

²⁶⁶ Decision 2012-362, paragraph 184.

²⁶⁷ Decision 2012-362, paragraph 189.

GTA.²⁶⁸ The Commission considers that the AESO has addressed these concerns in the customer contribution policy proposed in the application.

510. For all of the above reasons, the Commission rejects AltaLink's request to direct the reconvening of the CCP working group. Similarly, the Commission rejects AltaLink's proposal that the contribution policy recommendations of Devon be approved on an interim refundable basis, subject to change, pending the conclusion of CCP working group discussions.

6.3.2 Contribution policy principles

511. In argument, Devon submitted that Section 30(3)(a) of the *Electric Utilities Act* requires that market participants must be subject to "postage stamp" rates under the AESO tariff. That is, rates should not differ as a result of the market participant's location. However, transmission contribution policies are inconsistent with this requirement. A restrictive contribution policy, based on old, historical cost information has a disproportionate effect on northern resource extraction projects and, as such, is inconsistent with the premise of postage stamp rates.²⁶⁹

512. Devon noted that contributions are often measured in millions, or tens of millions, of dollars and discourage the load growth on which the current large scale build is premised. Further, to the extent that the contribution policy reflects old, historical cost information that has a disproportionate effect on northern resource projects, which tend to be more expensive, Devon submitted that this may fundamentally violate the policy intent of shielding remote transmission loads from their higher connection costs.²⁷⁰ Devon also argued that the AESO's proposed customer contribution policy created intergenerational equity issues.

513. AltaLink opposed the AESO's policy on the basis of its failure to address intergenerational equity concerns. In its argument, AltaLink submitted that there appeared to be agreement among the parties in the current proceeding that the following definition of intergenerational equity proposed by AltaLink within the 2012 CCP proceeding is reasonable:

Intergenerational equity is maintained when an investment mechanism results in similar proportions of investment and contribution for similar connection projects in similar circumstances over periods when different tariffs were in effect.

514. AltaLink noted during cross-examination that the AESO's witness, Mr. Martin, indicated that, of the three primary principles established in Decision 2012-362, the intergenerational equity principle is the principle that is most at risk if target investment coverage levels are not attained.

515. In reply argument, the AESO submitted that the Commission has addressed Devon's argument, that transmission contribution policies can be viewed as inconsistent with the postage stamp rate provisions set out in Section 30(3)(a) of the *Electric Utilities Act*, in previous tariff proceedings. For example, in Decision 2005-096, AESO 2005-2006 GTA, the Commission's predecessor found that the AESO's contribution policy aligned with the postage stamp principle. The AESO submitted that the findings in Decision 2005-096 remain applicable today.

²⁶⁸ Decision 2012-362, paragraph 191.

²⁶⁹ Exhibit No. 361.02, Devon argument, paragraphs 13-17.

²⁷⁰ Exhibit No. 361.02, Devon argument, paragraph 17.

516. The AESO submitted that submissions from both Devon and AltaLink, on the basis that AESO proposals failed to meet intergenerational equity requirements, ignored the finding, expressed clearly in Decision 2012-362, that providing an efficient price signal should be considered to be a more important policy objective than addressing concerns related to intergenerational equity.²⁷¹ The AESO submitted that its proposed methodology for establishing maximum investment levels based on all projects in the database acknowledges and responds to the Commission's finding that providing an efficient price signal is paramount when compared to intergenerational equity differences that may be reflected in the differing costs of transmission projects over time.

517. In its reply argument, the UCA also submitted that the Devon proposition that contribution policies can be viewed as inconsistent with postage stamp pricing has been considered previously and subsequently rejected. The UCA referenced the findings in Decision 2001-6²⁷² as an example.²⁷³ In this regard, the UCA submitted that, while Devon expressed concern that the AESO's proposed contribution policy may have a disproportionate effect on northern resource extraction projects, the UCA noted that geographic location is a factor, in addition to inflation, that has contributed to recent project cost increases. The UCA submitted that, in this context, it is reasonable to expect that an investment function based on 60 per cent coverage measured against all projects will lead to projects more expensive than the average receiving less than 60 per cent coverage.²⁷⁴

Commission findings

518. Certain contribution policy recommendations of Devon were advanced in part on the basis that, in Devon's view, the contribution policy proposed by the AESO is inconsistent with the postage stamp principle set out in Section 30(3)(a) of the *Electric Utilities Act*. In particular, Devon argued that having a high percentage of project costs not covered by investment for recent projects is a violation of the postage stamp principle because it has a disproportionate effect on northern resource extraction projects.

519. Both the AESO²⁷⁵ and the UCA²⁷⁶ identified prior decisions of the Commission's predecessor that have made it clear that a contribution policy that requires more expensive projects to pay a higher contribution is not a violation of the postage stamp principle.

520. In Decision 2005-096, the board considered the AESO's customer contribution policy in the context of Section 30(3) of the *Electric Utilities Act*, which was reproduced in that decision as follows:

30(3) The rates set out in the tariff

- (a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under

²⁷¹ Decision 2012-362, paragraph 40.

²⁷² Decision 2001-6: ESBI Alberta Ltd., 2001 General Rate Application, Part D: Customer Contribution Policy, Application No. 2000135, File No. 1804-1, February 2, 2001.

²⁷³ Exhibit No. 398.02, UCA reply, paragraph 48 (cites Decision 2001-6, page 56).

²⁷⁴ Exhibit No. 398.02, UCA reply, paragraph 50.

²⁷⁵ Exhibit No. 402.02, AESO reply refers to Decision 2005-096, page 19.

²⁷⁶ Exhibit No. 398.02, UCA reply refers to Decision 2001-6.

section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

521. The current language of Section 3(3) of the *Electric Utilities Act* is unchanged.

522. In its findings in Decision 2005-096, the board stated at page 45:

The Board notes that previous Board Decisions in respect of the AESO's predecessor, EAL, including Decision 2000-1^[277] and Decision 2001-6 examined the manner in which the postage stamp principle should coexist with the use of contribution policies to provide appropriate economic siting signals. In particular, the Board determined in Decision 2001-6 that because the contribution policy proposed by EAL did not have the effect of making the location of an electric distribution system on the transmission system or the geographic location of a POD within Alberta a consideration in how the contribution policy was applied, the contribution policy of EAL complied with the postage stamp requirements of Subsection 27(2)(b). Accordingly, the Board considers that the contribution policy of the AESO's existing tariff may also be judged to align with the postage stamp principle as described in Subsection 30(3). It did not need to be altered to be brought into compliance.

523. The Commission agrees with this view and finds that the AESO's proposed customer contribution policy does not violate the requirements of Section 30(3) of the *Electric Utilities Act* simply because it contemplates the use of a database that includes the costs of older projects, that may not have been constructed in more remote regions, where much of the current construction is taking place.

524. Both Devon and AltaLink have also asserted the importance of ensuring that the customer contribution policy is consistent with the intergenerational equity principle. In particular, they have asserted that the level of investment coverage should remain at a relatively constant percentage of the current cost of connection projects.

525. Both parties emphasized the importance of intergenerational equity on the basis of findings in Decision 2012-362 that the three principles, including intergenerational equity, were found to be more important than the set of five other principles that were put forward by the AESO for the Commission's consideration in the AESO's 2012 CCP application.

526. The Devon and AltaLink submissions, while emphasizing the importance of maintaining intergenerational equity, failed to address the following finding in Decision 2012-362:

...the Commission is of the view that by increasing levels of investment allowance, the price signal provided by the construction contribution policy is weakened, because it diminishes the incentive for connecting customers to request the most economical connection facilities consistent with GEIP and/or to take into account proximity to the existing or planned transmission system when considering alternative locations for the load to be served. In summary, and as discussed later in this decision, the Commission remains of the view that, at the end of the day, providing an efficient price signal is

²⁷⁷ Decision 2000-1: ESBI Alberta Ltd. 1999/2000 Phase I and II, Application No. 990005, File Nos. 1803-1, 1803-3, February 2, 2000.

considered a more important policy objective than intergenerational equity.²⁷⁸ [emphasis added]

527. The Commission remains of the view that, in the event a choice must be made, the provision of an efficient price signal is a more important policy goal for the AESO's construction contribution policy than intergenerational equity.

6.3.3 Investment coverage and scope of project cost dataset

6.3.3.1 Scope of project cost dataset

528. In the application, the AESO proposed that investment coverage be determined by assessing investment coverage over all 215 projects in its project cost database.²⁷⁹ In argument, the AESO proposed that the dataset used for determination of investment coverage should be expanded to reflect an updated connection project database considered in the preparation of the AESO's response to ACCESS-AESO-001.²⁸⁰

529. In its evidence, Devon proposed that the investment coverage level should be targeted at 60 per cent of new project costs. This result could be achieved by either:

- using the all project dataset, but setting the target coverage level to 70 per cent of all historic project costs,²⁸¹ or
- using a rolling average cost, reflecting several years of recent costs while maintaining a reasonable level of smoothing²⁸²

530. Devon suggested that a downside of the former option is that the multiplier to achieve a 70 per cent target would only be effective for a short period of time and would likely require frequent adjustment and debate. Accordingly, Devon suggested that the latter approach be adopted, whereby the AESO would target a 60 per cent coverage level against a five-year rolling dataset, composed of one forward and four past years.²⁸³

531. In its argument, Devon submitted that the three primary principles endorsed in the 2012 CCP proceeding (providing effective price signals, maintaining intergenerational equity, and being based on cost causation) are inherently forward looking and, as such, should reflect the following characteristics:

- price signals should reflect prices that will be experienced by projects in the current tariff year
- intergenerational equity should be maintained by using a stable 60 per cent investment coverage target in the current tariff year
- customers should pay 100 per cent of the project costs they cause to be incurred above the "bright line" for the current tariff year²⁸⁴

²⁷⁸ Decision 2012-362, paragraph 40.

²⁷⁹ Exhibit No. 26, paragraph 369.

²⁸⁰ Exhibit No. 366.01, AESO argument paragraph 225. Note that the proposal to use the expanded project cost database used in ACCESS-AESO-001 is considered as a separate matter in Section 6.3.3.3 of this decision.

²⁸¹ Exhibit No. 146.02, paragraph 56.

²⁸² Exhibit No. 146.02, paragraph 58.

²⁸³ Exhibit No. 146.02, paragraph 61.

²⁸⁴ Exhibit No. 361.02, Devon argument, paragraph 44.

532. Conversely, Devon submitted that basing the “bright line” on a dataset that includes a predominance of historic projects would violate these principles, since:

- investment price signals would reflect an arbitrary blend of past costs, not current costs
- intergenerational equity would be profoundly violated by reducing the effective contribution level far below historic levels, and far below the range of reasonableness
- customers would pay more of the costs than their connection had caused²⁸⁵

533. Devon submitted that including all historic projects in the updated dataset would result in a significant reduction in the actual coverage ratio. In particular, due to the dampening effect of older projects, including older projects in the dataset, results in only 48 per cent coverage for recent projects over the 2009 to 2013 period.²⁸⁶ This 12 per cent reduction in investment coverage amounts to an increased contribution of about \$2 million for an average customer,²⁸⁷ which would amount to a clear example of intergenerational inequity.²⁸⁸ This coverage ratio would decline even further if the cost of connection projects continues to exceed the level of inflation used by the AESO for its annual update process.

534. Devon noted that the Commission found in Decision 2012-362 that the inclusion of older, lower cost projects in the project dataset has the effect of dampening increases in investment coverage.²⁸⁹ However, Devon submitted that dampening changes in contribution levels was not one of the guiding principles that was accepted by the Commission, and also submitted that the use of historic project costs to establish contribution levels was not supported by the evidence in the 2012 CCP proceeding, or by any participant in that process.²⁹⁰ Devon also submitted that the removal of outliers from the data would further bias the contribution policy’s implementation.²⁹¹

535. In its argument, AltaLink submitted that while the evidence filed in the current proceeding puts the Commission no further ahead in the critical decision as to what level of investment should be considered to be excessive or insufficient,²⁹² the AESO did not rebut evidence filed on behalf of Devon that demonstrated the inappropriateness of assessing investment levels against a database including all projects.

536. Rather, AltaLink noted that in its response to AML-AESO-002(b),²⁹³ the AESO confirmed that, if the investment levels proposed in the application are assessed only against more recent projects, only 48 per cent investment coverage is achieved. AltaLink also noted that the AESO panel confirmed during cross examination that its analysis failed to account for

²⁸⁵ Exhibit No. 361.02, Devon argument, paragraph 45.

²⁸⁶ Exhibit No. 361.02, Devon argument, paragraph 46 (references AML-AESO-002 attachment, Exhibit No. 110.02).

²⁸⁷ Exhibit No. 361.02, Devon argument, paragraph 47 (references AML-AESO-002 attachment, Exhibit No. 110.02).

²⁸⁸ Exhibit No. 361.02, Devon argument, paragraph 48.

²⁸⁹ Exhibit No. 361.02, Devon argument, paragraph 51 (references Decision 2012-362, paragraph 189).

²⁹⁰ Exhibit No. 361.02, Devon argument, paragraph 52.

²⁹¹ Exhibit No. 361.02, Devon argument, paragraph 53.

²⁹² Exhibit No. 359.02, AltaLink argument, paragraph 25.

²⁹³ Exhibit No. 110.01.

changes in project characteristics.²⁹⁴ Considering this, AltaLink submitted that the AESO should have proposed an approach that takes into account only recent projects.²⁹⁵

537. AltaLink noted that, in its response to AUC-AESO-040, the AESO indicated that it regularly updates the connection project database and, therefore, using a database of all projects, to determine investment coverage, will gradually recognize changes that occur in service characteristics, functionality, and standards that result over time. The AESO also stated that if service characteristics, functionality, and standards change over a short period of time, the use of an all-projects database to determine investment coverage will delay or dampen the increase in investment levels that would otherwise occur.²⁹⁶

538. AltaLink submitted that the difficulty it has with the AESO's position as set out in the AUC-AESO-040 response, is that service characteristics, functionality, and standards that drive project costs have changed over a lengthy period of time, and not over a short period of time, as suggested by the AESO. As such, the AESO's approach of including all projects in the database against which investment coverage is assessed has the effect of embedding a mismatch of assumptions into the investment formula. Furthermore, the AESO's current support of the use of a longer time frame project database is inconsistent with the position it took during the 2012 CCP proceeding, where it advocated for a shorter term database, in part on the basis that doing so would better reflect changes in service characteristics, functionality, and standards that occur over time.²⁹⁷

539. The AESO responded to both Devon and AltaLink in its argument submissions. With regard to the position advocated by Devon to use a five-year rolling average to assess investment coverage on the basis that: (1) its approach would reflect several years of recent costs of while maintaining a reasonable degree of smoothing; (2) because a five-year window would provide stability and would somewhat mitigate sudden cost changes not truly reflective of reasonable forecast changes, and; (3) that the dampening effect caused by including older projects in the project cost database would create pressure to revise the contribution policy, leading to renewed litigation and instability, the AESO submitted that these concerns are unsupported by the evidence.

540. In particular, the AESO noted that in responding to ACCESS-AESO-002(d),²⁹⁸ it found that the investment function derived by targeting 60 per cent coverage against the updated project dataset provided in ACCESS-AESO-001 resulted in 67 per cent coverage over the most recent greenfield projects included in the updated dataset. Given this, the AESO submitted that Devon's concern about "the artificial lowering introduced by including older projects"²⁹⁹ is unwarranted. Additionally, the AESO submitted that the Devon proposal does not address Commission concerns that higher investment levels may encourage higher project costs with the potential for "investment cliffs" caused by the unusual or temporary increases in project costs. Last, the AESO disputed the claim of Devon that using an historic database results in coverage

²⁹⁴ Transcript, Volume 2, page 206 (referenced at paragraph 34 of AltaLink argument).

²⁹⁵ Exhibit No. 359.02, AltaLink argument, paragraph 26.

²⁹⁶ Exhibit No. 109.01 of AUC-AESO-040, referenced at paragraph 38 of AltaLink argument.

²⁹⁷ Exhibit No. 359.02, AltaLink cites AUC-AESO-023(c) and AUC-AESO-033(b) from 2012 CCP, Proceeding No. 1162 evidence at paragraph 40 of its argument.

²⁹⁸ Exhibit No. 112.01.

²⁹⁹ Exhibit No. 146.01, referenced at paragraph 237 of the AESO argument.

that is lower and unpredictable, submitting that it is counter-intuitive that a larger sample would be less predictable than an assessment of investment coverage against a smaller dataset consisting only of recent projects.

541. In reply to AltaLink, the AESO submitted that AltaLink's suggestion that any formula accepted by the Commission should, at a minimum, achieve a 60 per cent level of investment when applied to actual projects covered by the applied-for tariff infers that it was the Commission's intent that 60 per cent coverage should apply to specific projects, rather than all projects in the database. This interpretation is not supported by the language used in Decision 2012-362. In particular, the AESO noted that the Commission expressed concern about moving away from the approach of determining investment coverage based on all available connection projects, as evidenced from the Decision 2012-362 passage reproduced below:

In past ISO tariffs, investment coverage was determined based on all available connection project cost information, the same dataset used to estimate the average cost function. Ordinarily, as part of a comprehensive tariff application, the dataset would be updated with new connection projects and the most recent cost data for the existing connection projects. In this way, the higher cost projects increase the overall average cost, but the increase would be dampened by older, lower cost connection projects (even though they are escalated by inflation). The Commission has some concern with moving away from this approach. The Commission agrees that investment coverage should recognize the changes to service characteristics, functionality, and standards that occur over time, but at the same time investment coverage should not incent increasing costs due to increased radial line requirements, transmission voltage level, substation configuration, varying geography or unique construction and environmental conditions. The Commission considers that the regular updating of connection project data that occurs as part of a comprehensive tariff application should sufficiently capture the changes to service characteristics, functionality, and standards that occur over time. The update to the cost data and to the average cost function will also serve to rectify any potential "investment cliffs" as evidenced between 2010 and 2011.³⁰⁰ [emphasis added by the AESO]

542. The AESO submitted that the foregoing passage demonstrates a clear intent on the part of the Commission that the contribution policy should target a 60 per cent investment coverage level, assessed over all connection projects.

543. In its reply argument, AltaLink noted that in an effort to demonstrate that the concerns that caused Devon to propose the use of a five-year rolling average dataset as the basis for assessing investment levels, the AESO attempted to demonstrate that investment coverage is reasonably close to the 60 per cent target after it included more recent projects as part of its response to ACCESS-AESO-002(d). However, AltaLink noted that the AESO's analysis relied on a sample of only five projects and was not a representative sample of the projects to which the actual tariff will apply. Further, AltaLink reasserted its objection to the AESO using a long-term project cost database to affect a dampening of changes in contribution levels caused by unusual or temporary cost increases.

544. In its reply argument, the UCA disagreed with AltaLink's suggestion that the investment coverage accepted by the Commission should be achieved when applied to the actual projects

³⁰⁰ Decision 2012-362, paragraph 189.

covered by the AESO tariff application under consideration. Noting that the AESO has requested that its tariff apply for a three year period, the UCA noted that AltaLink's suggestion amounts to a request for a dataset scope even shorter than the five-year period recommended by Devon.³⁰¹

545. In response to AltaLink's suggestion that the AESO's proposed 60 per cent investment coverage target would amount to only 48 per cent coverage when applied to projects with in-service dates after 2010, the UCA submitted that the average investment coverage in any five-year period may not equal 60 per cent, since factors other than inflation can affect average project costs in any window as short as five years. Notwithstanding, the UCA submitted that it was significant that the analysis provided for the AESO's response to ACCESS-AESO-002(d) showed that when the updated database discussed in ACCESS-AESO-001 is utilized, the average investment coverage for projects with in-service dates of July 1, 2014, or later would actually exceed 60 per cent.³⁰² The UCA similarly referenced the investment coverage for projects with in-service dates after July 1, 2014, in response to the Devon submission that the AESO's proposed contribution policy would provide only 48 per cent investment coverage for projects over the 2009 to 2013 period.³⁰³

546. In reply argument, Devon reaffirmed its view that the inclusion of long-term historic connection project data has the effect of lowering the investment provided to current projects associated with higher than historical unit costs. It rejected the AESO's suggestion that the continued use of the historic dataset is justified by the fact that it obtains 67 per cent coverage for recent projects when it uses the updated dataset from ACCESS-AESO-001 should be discounted because the AESO's analysis only used five projects with in-service dates after July 1, 2014. Devon submitted that contribution policies are not an appropriate tool for managing project cost increases, and submitted that dampening project cost increases is not a contribution policy principle, and cannot be used to justify the AESO's investment policy.

547. Enbridge did not file argument but did file reply argument. In its reply argument, Enbridge fully supported the position of Devon.

Commission findings

548. A proposal to use a shorter term dataset consisting of recent projects as a basis for assessing investment coverage levels was considered by the Commission in the 2012 CCP application proceeding³⁰⁴ and as noted by the AESO in this proceeding, the Commission expressed concerns about adopting this approach.³⁰⁵

549. The Commission is not persuaded by the evidence on the record of this proceeding that it should abandon the use of a longer term dataset to assess investment coverage and the level of the multiplier for the period of time that the 2014 AESO tariff and subsequent updates are in effect.

550. Further to the Commission's finding in Section 6.3.2 of this decision, the provision of an efficient price signal must, when there is a conflict, take precedence over principles of inter-

³⁰¹ Exhibit No. 398.02, UCA reply, paragraph 40.

³⁰² Exhibit No. 398.02, UCA reply, paragraph 42.

³⁰³ Exhibit No. 398.02, UCA reply, paragraph 51.

³⁰⁴ Application No. 1067193, Proceeding No. 1162, 2012 Construction Contribution Policy, Decision 2012-362.

³⁰⁵ Decision 2012-362, paragraph 189.

generational equity. Accordingly, the Commission will not direct the use of a dataset that only includes recent projects solely on the basis that the AESO's contribution policy is required to reflect intergenerational equity.

551. The Commission has considered Devon's and AltaLink's characterizations of the Commission's reference to the "dampening" effect of using a longer term dataset that is referred to in Commission findings in Decision 2012-362. In particular, certain statements by Devon and AltaLink suggest that the reference to the dampening effect in findings of Decision 2012-362 reflected a desire to slow down artificially the rate of increase in investment levels such that investment levels lag behind the current cost of connection projects. This interpretation is not correct.

552. As set out in Decision 2005-096,³⁰⁶ the Commission has acknowledged that, to the extent changes in service characteristics, functionality, and standards may occur over time, it is reasonable for the Commission to consider the effect of such changes when considering investment levels. Furthermore, to the extent that higher levels of service, functionality, and standards may cost more to provide, the Commission considers that the inclusion of higher cost data points into a cumulative dataset provides a means of recognizing the possibility that changes in service, functionality and standards have driven up the cost of service. This effect should be taken into account when assessing the level of investment coverage offered under the tariff.

553. However, the Commission notes that, while AltaLink has asserted that the higher cost of more recent projects reflects a permanent structural change in the cost of projects that is driven by a change in service, functionality, and standards, rather than a short-term temporary change, it provided no evidence to support its claim. The Commission considers it more likely that the costs of more recent projects reflects remote geographic locations, high competition for inputs, and the fact that many industrial market participants requesting connection projects in more recent years have demonstrated a willingness to pay for completing their connection projects as quickly as possible. There is no evidence that these circumstances reflect a permanent change to the Alberta environment.

554. For all of the above reasons, the Commission favours the use of a long-term dataset, where the cost of projects from any period is normalized to a current year value to reflect current costs. Within this framework, the Commission considers the inclusion of higher new data points into the dataset used for assessing investment coverage to be beneficial, because it acknowledges the possibility that changes in service, functionality, and standards may be part of the reason for the observed increase. To the extent that the use of a longer term dataset consisting of a larger number of observations "dampens" the effect of any single data point, the Commission considers this to be fully consistent with the Commission's findings in Decision 2012-362.

6.3.3.2 Target investment coverage level

555. The AESO proposed several principles in its 2012 CCP, which, it argued, the Commission found to provide a reasonable basis for assessing its proposed construction contribution policy in Decision 2012-362. In addition, the AESO considered that the Commission supported the continued use of an average cost multiplier methodology to determine maximum investment levels and that, in the same decision, the Commission had directed that the

³⁰⁶ Decision 2005-096, page 44.

multiplier be determined to provide an investment coverage level of approximately 60 per cent over all projects in the project database.³⁰⁷

556. In view of this understanding, the AESO indicated that it had determined that a multiplier of 0.79 would provide 60 per cent investment coverage over all 215 projects in the database.³⁰⁸ The AESO noted that the use of this multiplier led to the investment levels for customers served under Rate DTS with and without Rate PSC, set out in subsection 8(2) of Section 8 of its proposed tariff. These resulting investment levels are reproduced in Table 1.

Table 1. Applied-for maximum investment function

Tier	Investment for service under Rate DTS	Investment for service under Rate DTS with Rate PSC
Substation fraction (for new points of delivery only)	\$21,700/year	\$4,560/year
First (7.5 × substation fraction) MW of contract capacity	\$35,000/MW/year	\$7,350/MW/year
Next (9.5 × substation fraction) MW of contract capacity	\$17,450/MW/year	\$3,665/MW/year
Next (23 × substation fraction) MW of contract capacity	\$12,050/MW/year	\$2,530/MW/year
All remaining MW of contract capacity	\$7,700/MW/year	\$0/MW/year

Source: Exhibit No. 26, revised tariff application, paragraph 371.

557. In its intervenor evidence, Devon submitted that, in recent years, the AESO's investment policies have been inconsistent, as evidenced by the fact that project cost coverage changed from 60 per cent in 2010 to 32 per cent in 2011. Devon submitted that the observed volatility in cost coverage not only creates intergenerational inequity, it acts to diminish investors' confidence in the regulatory process.³⁰⁹

558. Devon submitted that while there were strong arguments favoring the 70 per cent coverage level proposed by the AESO in the 2012 CCP proceeding, it supported the adoption of the 60 per cent investment coverage level discussed in Decision 2012-362 and adopted by the AESO in the current proceeding as an enduring contribution calculation target. Devon submitted that even though a 70 per cent target would be of substantial benefit, the benefit of standardizing on a 60 per cent target was far more important to customers concerned with commercial certainty and regulatory stability.³¹⁰

559. Devon prepared calculations showing that by 2021, the adoption of Devon's proposed investment levels would only increase rates to large industrial customers by about one per cent as compared to the AESO's proposed levels. Devon submitted that this level of rate effect is reasonable and successfully balances the contribution principles of intergenerational equity and economically efficient price signals.³¹¹

560. In argument, the AESO re-summarized the Decision 2012-362 findings that it took into account to set the investment levels proposed in the application, and noted that it reconvened

³⁰⁷ Exhibit No. 26, paragraph 369.

³⁰⁸ Exhibit No. 26, paragraph 369.

³⁰⁹ Exhibit No. 146.02, paragraph 2.

³¹⁰ Exhibit No. 146.02, paragraph 18.

³¹¹ Exhibit No. 146.02, paragraphs 90-91.

participants in its 2012 CCP consultations and presented the outcome of these discussions in consultations with stakeholders leading to the development of the present tariff application.

561. The AESO noted that in AUC-AESO-019(b),³¹² it explained that its rationale for targeting 60 per cent coverage level, measured over all connection projects in its POD cost dataset, was based on Commission findings in Decision 2012-362 that:

- the principle of intergenerational equity is not sacrificed at investment coverage levels of approximately 60 per cent³¹³
- the investment coverage and reasonable range proposed by the AESO appeared to be too high³¹⁴
- the Commission had concerns with moving away from the approach whereby investment coverage was assessed against a dataset that contained both new connection projects and existing connection projects³¹⁵

562. The AESO also noted that its response to AUC-AESO-019(b) cited Decision 2010-606, in which the Commission stated:

The Commission considers that the overall intent of the contribution policy and maximum investment levels is to achieve a reasonable balance of what an individual customer pays upfront through a customer contribution relative to what all customers in a particular rate class pay through ongoing rates.³¹⁶

563. The AESO noted that the AUC-AESO-019(b) response also reflected its view that judgement is required to determine a “reasonable balance” that must consider multiple factors, and submitted that the reasonable balance would reflect the matters from Decision 2012-362 findings noted above. The AESO also submitted in that response that a target level coverage of 60 per cent applied over all projects balanced the principles of:

- providing effective price signals
- maintaining intergenerational equity
- reflecting cost causation

564. The AESO noted that its response to AUC-AESO-038 further demonstrated that its proposed 60 per cent investment coverage and resulting 0.79 multiplier reasonably satisfied contribution policy principles in light of Decision 2012-362 and requested that the Commission approve the maximum investment levels determined pursuant to the updated connection project database set out in its response to ACCESS-AESO-001.

565. In its argument, Devon reaffirmed the position it had advanced in its evidence in support of investment coverage levels at 60 per cent assuming that only current project costs were used.

³¹² Exhibit No. 109.01.

³¹³ Decision 2012-362, paragraph 180.

³¹⁴ Decision 2012-362, paragraph 184.

³¹⁵ Decision 2012-362, paragraph 189.

³¹⁶ Decision 2010-606, paragraph 435.

566. Devon noted that at a 60 per cent coverage level, over three quarters of customers would pay a contribution, thereby exposing these customers to the economic discipline intended by the policy.

567. Devon further submitted that given the overall rate effect of the cost of the current transmission system, the choice of investment level will have little effect upon increased transmission costs.³¹⁷ In this regard, Devon noted that if the Commission utilizes techniques such as including lower unit cost past projects to reduce investment coverage from a 60 per cent coverage to 40 per cent, this would only decrease the projected 2013 to 2023 period rate increase by two per cent, from a 91 per cent increase to an 89 per cent increase.³¹⁸

568. Devon submitted a final consideration in assessing the investment level that should be targeted is that high contributions may cause project deferrals or cancellations. Devon submitted that while the AESO does not disclose preliminary economic evaluations for commercial sensitivity reasons, in the experience of Devon witness, Depal Consulting, contributions are not an insignificant component of some customer's economic project decisions.³¹⁹

569. In its argument, AltaLink considered that the AESO's proposed investment formula failed to address concerns outlined by the Commission in Decision 2012-362, and did not meet the principles approved by the Commission in that decision.

570. AltaLink submitted that while the AESO proposed that an optimal contribution policy should satisfy the first three of eight suggested principles in the 2012 CCP proceeding, the AESO's proposed formula with a 60 per cent investment level does not achieve all three of these principles. In particular, AltaLink submitted that because the proposed customer contribution policy fails to consider adequately the Alberta construction environment and resulting effect on projects to which the tariff will apply, the investment coverage proposed by the AESO does not satisfy the principle of intergenerational equity.

571. To preserve intergenerational equity, AltaLink submitted that the Commission must determine the level at which investment is neither excessive, nor insufficient. AltaLink submitted that providing certainty to market participants on a go-forward basis that they can expect a certain level of investment, regardless of the year in which they connect to the system, preserves the principle of intergenerational equity.

572. In its reply argument, the AESO responded to Devon's argument that its proposed contribution policy disproportionately effects new customers and discourages load growth. The AESO indicated that it was AESO's experience that material construction contribution levels have little, if any, effect on the number or size of system access service requests it receives.³²⁰ Instead, market participants appear to respond to the price signal provided by a construction contribution by optimizing the service location on their property to minimize the level of the contribution.³²¹ The AESO submitted that there is no evidence in the current proceeding to

³¹⁷ Exhibit No. 361.02, Devon argument, paragraph 17.

³¹⁸ Exhibit No. 361.02, Devon argument, paragraph 20.

³¹⁹ Exhibit No. 361.02, Devon argument, paragraph 21.

³²⁰ Exhibit No. 402.02, AESO reply argument, paragraph 48, citing Exhibit No. 109.06, response to AUC-AESO-017 from 2012 CCP proceeding.

³²¹ Exhibit No. 402.02, AESO reply argument, paragraph 48, citing Exhibit No. 109.06, response to AUC-AESO-017 from 2012 CCP proceeding.

suggest that the investment levels proposed by the AESO would discourage load growth in Alberta.

573. In its reply argument, the UCA responded to the position of both AltaLink and Devon. In response to AltaLink, the UCA submitted that intergenerational equity is not achieved by each customer receiving the same percentage coverage of total project costs. Instead, the UCA submitted that intergenerational equity is achieved by similar customers receiving approximately the same amount of investment, adjusted for inflation. Accordingly, the UCA submitted that new customers should not receive a higher level of investment simply because factors other than inflation have contributed to higher project costs.³²²

574. In response to Devon, the UCA disagreed that providing a forward looking assurance of a 60 per cent investment coverage level would make sense to customers because they would understand that, on average, they would have to pay 40 per cent of a connection project's cost. The UCA submitted that knowing that the average for all customers would be a 40 per cent contribution does not assist individual customers in determining the contribution required for a particular project. Conversely, the UCA submitted that the current policy of establishing maximum investment levels, which will escalate with inflation, is much more helpful to a specific customer in determining the contribution that will be required for a particular project.³²³

Commission findings

575. Both Devon and AltaLink assert that intergenerational equity is obtained only if the percentage investment coverage level remains constant when compared to the full cost of current connection projects. This position also contributes to Devon's and AltaLink's views that a project cost dataset that includes non-current projects that, because of vintage, costs less on average than current projects, requires target investment levels to be higher to achieve intergenerational equity. In other words, the contribution policy should be set at 60 per cent of the current cost of projects in order to be similar to the contribution that would have been received by customers in the past.

576. The underlying assumption in this argument is that the costs of current projects are only higher due to inflationary factors. That is, adjusted for inflation, a 60 per cent contribution for a past project would be similar to a 60 per cent contribution for a current project. However, as pointed out by the UCA, the costs of current projects are higher, on average, than the inflation adjusted costs of projects from earlier periods. In particular, evidence in the current proceeding suggests that the comparatively higher costs of recent projects reflects, at least in part, the choice of market participants to build connections in high cost locations, to undertake construction during high cost conditions, such as the short term effects of a highly competitive market for project inputs, or to request the completion of projects within compressed time frames.

577. A customer contribution policy that provides efficient price signals will ensure that economic discipline is exerted on the connection decisions of customers. The Commission considers that the AESO proposal to set the target investment level, so that it accounts for the entire costs of 60 per cent of projects, provides a sufficient price signal.

³²² Exhibit No. 398.02, UCA reply, paragraph 44.

³²³ Exhibit No. 398.02, UCA reply, paragraph 54.

578. The Commission also recognizes that at least some customers desire a firm commitment respecting the target for customer contributions in order to assist them in their decision-making. It is difficult for a customer contribution policy, whose target level is changing frequently, to provide a consistent price signal to customers. Nonetheless, parties may wish to provide evidence in a future comprehensive AESO tariff application proceeding that a different investment coverage target may be warranted.

6.3.3.3 Use of updated project cost data

579. In argument, the AESO noted that it had provided an updated investment levels workbook based on the updated connection project database that it prepared for its response to ACCESS-AESO-001 and AESO requested that the maximum investment levels reflecting the updated connection project database used for ACCESS-AESO-001 should be used to set maximum investment levels for the approved tariff.

580. Devon submitted that the updated project database set out in ACCESS-AESO-001 should be used for the purposes of this proceeding because:

- the Commission and its predecessors have long taken the position that the most current data should be used in the regulatory process³²⁴
- the project data available proposed for the current proceeding is over a year out of date, reflecting only information available as of early 2012³²⁵
- as part of the information request process, the AESO has filed an updated connection project database that includes all projects where a facility application has been filed with the Commission³²⁶

581. The CCA also supported the use of a revised database as presented in ACCESS-AESO-001 as the basis for determining investment levels, and submitted that using the expanded dataset would be consistent with past regulatory practice to use best available information.³²⁷

582. The UCA noted that, in the oral hearing, the AESO proposed to use the project database as updated for its ACCESS-AESO-001, and also noted that the AESO indicated that it could make additional updates to the project cost dataset to reflect any further updates arising during the course of the proceeding.³²⁸ However, the UCA submitted that the AESO did not indicate in ACCESS-AESO-001 that it intended to use the updated dataset, let alone make even further updates. The UCA also noted that the AESO indicated in an undertaking response that it would expect to take approximately half of the 80 man-hours used to prepare ACCESS-AESO-001 to ensure that all numbers were correct and up to date.³²⁹ In light of the above, the UCA submitted that the updated project database used to prepare ACCESS-AESO-001 has not been sufficiently scrutinized to allow meaningful review of the data. Accordingly, the UCA submitted that the Commission should direct the AESO to use the project dataset filed with the application for its compliance filing for this proceeding.

³²⁴ Exhibit No. 146.02, paragraph 26.

³²⁵ Exhibit No. 146.02, paragraph 26.

³²⁶ Exhibit No. 146.02, paragraph 28, citing ACCESS-AESO-001 from Exhibit No. 112.01.

³²⁷ Exhibit No. 371.02, CCA argument, paragraph 113.

³²⁸ Exhibit No. 364.02, UCA argument, paragraph 75 (referencing Transcript Volume 2, pages 172-173).

³²⁹ Exhibit No. 364.02, UCA argument, paragraph 76 (referencing Transcript Volume 2, pages 176-177).

583. In its reply argument, Devon submitted that the UCA had every opportunity to review and test the updated data, and failed to conduct any examination of this in the oral hearing. Devon further submitted that there is no reason to expect that the data, as presented by the AESO, is not credible and noted that in the unlikely event that an issue with the data is identified, the AESO indicated that there would be an opportunity to pursue this in the GTA compliance filing process.³³⁰ In any event, given that the AESO has supported the use of this updated data, Devon submitted that if there was any cause for concern, there is every reason to believe that the AESO would have pointed this out. As the most current information available, it should be used in the updated contribution calculations.

Commission findings

584. The Commission finds that the updated dataset used to prepare the response to ACCESS-AESO-001 should be used to determine the maximum investment level for the 2014 tariff because it represents the most current information available.

585. The Commission acknowledges the UCA's concern that the updated data workbook has not been extensively vetted and that the AESO's intention to utilize further updated data was not disclosed until a relatively late stage in the proceeding. With regard to the dataset used to prepare the response to ACCESS-AESO-001, parties had an opportunity to test this evidence during the oral hearing. The Commission understands that the updated data workbook has been prepared using this dataset. Although the AESO did not indicate that it would be using the updated workbook until the oral hearing, the Commission considers the preparation of the workbook is a fairly straightforward exercise. As there was an opportunity to test the dataset that formed the basis of the inputs into the workbook, the Commission is prepared to accept the results set out in the workbook for the purposes of this decision. However, the AESO is directed to identify any changes and adjust any results in its application of the updated dataset as part of its compliance filing. As there has been no opportunity to test any changes to the dataset since the oral hearing, the AESO is directed to remove any further changes to the dataset that it may have employed in the workbook that were not disclosed in the response to ACCESS-AESO-001.

6.3.3.4 Exclusion of outliers for investment level assessment

586. The CCA supported the Devon proposal to use a five-year window of project costs for the determination of the investment function multiplier. The CCA noted that in the proceeding which led to Decision 2012-362, the AESO proposed to use only recent projects to establish a multiplier for setting investment levels, and submitted that the key consideration is whether the dataset used is reflective of investments in customer facilities on a forward looking basis. However, as a check and balance, the CCA proposed that in conjunction with its support of a five-year window, it proposed that outlier projects with costs falling outside of one standard deviation from the mean of the entire dataset be excluded.³³¹

587. In reply argument, Devon noted that while the CCA supported its proposal to use a five-year dataset, the CCA proposal to exclude any outlier projects that lie more than one standard deviation from the mean of the entire five-year dataset is a statistical question that requires thorough expert testing before the Commission can make an informed decision and submitted

³³⁰ Transcript, Volume 2, page 173 (referenced in paragraph 41 of Devon reply argument).

³³¹ Exhibit No. 371.02, CCA argument, paragraph 118.

that if the Commission wishes to pursue this matter further, it should be done at the time of the AESO's next GTA.³³²

588. Although the AESO did not support Devon's proposal to use a five-year rolling dataset, it provided a specific response opposing the CCA's proposal to exclude outliers in its reply argument. The AESO noted that in its response to IPCAA-AESO-001(g),³³³ in its investigation of outliers for the preparation of the application, it generally found that there were reasons why costs for outlier data points were significantly higher or lower than the average, and thus, there was no basis to exclude them. The AESO submitted that a key advantage of basing the cost function on all projects in the database is that it increases the likelihood that the cost function will represent all points of delivery on the transmission system. Conversely, the AESO submitted that excluding outliers could result in a cost function that is less representative of all points of delivery or that the cost function will be biased toward a particular subset.³³⁴ In conclusion, the AESO submitted that while excluding outliers could add stability if the investment levels are determined only on the basis of recent projects, if the purpose of including recent projects is to reflect cost changes, excluding outliers would run counter to that purpose.³³⁵

Commission findings

589. In sections 6.3.3.1 and 6.3.3.3 of this decision, the Commission approved the use of a longer term dataset, including the expansion of the dataset to include the additional projects considered for the preparation of the response to ACCESS-AESO-001. Consequently, the CCA's request to exclude outliers in Devon's proposed five-year rolling dataset is moot.

6.3.4 Effective date for investment level changes

590. In Section 7.4.2 of the application, the AESO noted that the Commission did not approve the investment levels proposed by the AESO in the 2012 CCP application in Decision 2012-362.

591. Considering this, the AESO proposed that investment levels set out in the application should be effective on the same date as the 2014 ISO tariff itself, which the AESO has requested to be July 1, 2014.³³⁶ The AESO revised this date to October 1, 2014 in its argument submission in recognition of the fact that a decision would not be released by July 1, 2014, as originally anticipated. In the alternative, the AESO sought an effective date no earlier than the first of the month at least 60 days after the Commission's decision in this proceeding so that testing of rates for the AESO's billing system can occur.³³⁷

592. In conjunction with its evidence that investment level updates should be applied effective July 1, 2012 and subsequently effective October 1, 2013, the Devon evidence set out proposed investment level functions reflecting a coverage level of 60 per cent and the cost function and multiplier proposed in the 2012 CCP proceeding.

³³² Exhibit No. 396.01, Devon reply argument, paragraphs 76-78.

³³³ Exhibit No. 110.01.

³³⁴ Exhibit No. 402.02, AESO reply argument, paragraph 66.

³³⁵ Exhibit No. 402.02, AESO reply argument, paragraph 67.

³³⁶ Exhibit No. 26, application, paragraph 372.

³³⁷ Exhibit No. 366.01, AESO argument, paragraph 4.

593. Specifically, for the period July 1, 2012 to October 1, 2013, Devon requested approval of a cost function based on an investment multiplier of 1.06 applied to a power function of $Cost = 1,976,728(MW)^{0.5810}$. After October 1, 2013, Devon requested approval of a cost function based on an investment multiplier of 1.04 applied to a power curve function of $Cost = 2,444,600(MW)^{0.5707}$, derived using the updated project costs dataset provided in ACCESS-AESO-001. The resulting investment functions are set out in Table 2.

Table 2. Maximum investment levels proposed by Devon

Tier	Level effective July 1, 2012	Level effective October 1, 2013
Basic	\$23,300/year	\$29,200/year
First 7.5 MW	\$41,950/MW/year	\$49,650/MW/year
Next 9.5 MW	\$21,650/MW/year	\$25,150/MW/year
Next 23 MW	\$15,200/MW/year	\$17,550/MW/year
Remainder	\$9,900/MW/year	\$11,300/MW/year

Source: Exhibit No. 146.02, pages 19 and 20.

594. Devon submitted that the parties who participated in the 2012 CCP proceeding expected that proceeding to provide a final resolution of contribution policy and implementation matters. Unfortunately, Devon submitted this was not the case, such that a number of issues from the 2012 CCP proceeding were brought forward into the present proceeding. However, Devon submitted that as the AESO has not identified any fundamental contribution policy or implementation concerns in the current tariff application that depart from those considered in the 2012 CCP proceeding, the contribution policy principles as outlined in Decision 2012-362 should, therefore, be taken as final and implementation of revised investment levels should begin, as anticipated by the AESO in its 2012 CCP application, on July 1, 2012.³³⁸

595. The Devon evidence further submitted that the 2013 tariff and its associated investment levels should become effective on October 1, 2013, coinciding with the AESO's annual update. Finally, Devon submitted that, given the timing of the current proceeding, the next update should be completed by the AESO in early 2015, or on such other dates as the Commission may direct.³³⁹

596. Section 7 of the Devon evidence (entitled "Timing of Contribution Policy Implementation") provided additional detail to support the rationale for its implementation timing. In that section, Devon submitted that:

- participants in the 2012 CCP proceeding acted in good faith with an understanding that a decision would be reached and the matter would be closed³⁴⁰
- for procedural reasons, the Commission determined that the contribution policy and DTS cost function should be considered together in the next AESO GTA proceeding³⁴¹

³³⁸ Exhibit No. 146.02, paragraph 6 (citing Decision 2012-362, paragraph 12).

³³⁹ Exhibit No. 146.02, paragraph 6.

³⁴⁰ Exhibit No. 146.02, paragraph 70.

³⁴¹ Exhibit No. 146.02, paragraph 71.

- in a letter dated March 11, 2013, the Commission found that a policy finding made Decision 2012-362 regarding the timing of contribution policy implementation could be raised in the AESO's next comprehensive tariff application³⁴²
- implementing a retroactive effective date for construction contribution levels is not barred by either legislation or policy³⁴³

597. Devon noted that in its response to ACCESS-AESO-003(d),³⁴⁴ the AESO addressed why, notwithstanding having proposed a retroactive effective date in the 2012 CCP application, it chose to recommend that the contribution policy changes become effective at the time of the approval of the current tariff application. Devon took note that, in that response, the AESO indicated that while the 2012 CCP would have resulted in about a 64 per cent increase in investment coverage, the current application proposed a more modest increase in investment levels that would result in about a 12 per cent increase in coverage. The AESO did not consider that the modest increase would warrant retroactive treatment and would be unlikely to influence a market participant's decision to delay a project.

598. Devon submitted that delaying the implementation of investment level changes would have the following adverse effects:

- reduced confidence or trust in the regulatory process that may encourage some market participants to delay major projects
- unfair treatment of market participants with projects proceeding within the window between 2012 and 2014
- greater likelihood that customers will be paying different amounts for the same service, which would be at odds with the intent of postage stamp tariffs and Section 30(3)(a) of the *Electric Utilities Act*

599. Devon submitted that procedural fairness claims should not be allowed to displace the reasonable expectations of market participants that the Commission would rule in a timely fashion on the matters discussed in the 2012 CCP proceeding. Further, Devon submitted that as the matters raised to date in the current proceeding should be considered minor refinements to the contribution calculation process, there are no evidentiary grounds for delaying a final determination on matters considered in the 2012 CCP proceeding.³⁴⁵

600. In Section 7.3.1 of its argument, the AESO noted that while it had requested retroactive effective dates for investment level changes proposed in its 2012 CCP application, the AESO indicated that it was not requesting retroactive effective dates in this proceeding for the reasons outlined in its response to ACCESS-AESO-003(d):

The AESO's concern in the contribution policy application was that since the AESO had applied for a material increase in investment levels, some market participants would attempt to delay projects until the applied-for investment levels became effective. The AESO considers the more modest increase applied for in this application would be unlikely to influence a market participant to delay a project. Even if the Commission

³⁴² Exhibit No. 146.02, paragraph 72.

³⁴³ Exhibit No. 146.02, paragraph 73.

³⁴⁴ Exhibit No. 112.01.

³⁴⁵ Exhibit No. 146.02, paragraphs 79-80.

ultimately approves significantly higher investment levels, the AESO considers that most market participants would not anticipate such approval given the applied-for levels and therefore would not attempt to delay their projects.³⁴⁶

601. The AESO submitted that there is no indication in Decision 2012-362 that contribution levels would be implemented retroactively to July 1, 2012. Accordingly, the AESO submitted that market participants have already made decisions with respect to their project schedules with no anticipation of retroactivity. Accordingly, the AESO submitted there is no reason to apply retroactive implementation of investment levels to address potential delays to project schedules.

602. The AESO submitted that the Devon position with respect to effective dates ignores the concern that retroactive implementation of the proposed investment level changes would result in misalignment between the cost function used to determine investment levels and the cost function used for the point of delivery charge in Rate DTS. The AESO noted that the Commission expressed concern about such misalignment in its findings in Decision 2012-362. The AESO submitted that this supported its recommendation that investment level changes should take place on the same date that the balance of the 2014 AESO tariff will take effect. Additionally, the AESO submitted that investment levels implemented on October 1, 2013 as part of the 2013 tariff update should also not be adjusted retroactively.

603. In its argument, Devon submitted that if 2011 contribution levels are imposed on customers from July 1, 2012 through to late 2014, a massive potential intergenerational inequity, potentially over a hundred million dollars, would be inflicted on a small number of new customers.³⁴⁷ Devon restated positions discussed in its evidence that to achieve fairness and avoid further intergenerational equity issues, July 1, 2012 should be set as the implementation date for revised investment levels. As such, customers receiving permit and license between July 1, 2012, and the 2013 tariff implementation date should receive investment based on 60 per cent coverage using the customer contribution policy data and analysis, with subsequent connections receiving contributions at the level determined in the 2014 proceeding until its next annual change.³⁴⁸

604. Devon submitted that implementing the original July 1, 2012 timeframe requested by the AESO and most, if not all, stakeholders, using the dataset that would have been available at the time, would be a fair and reasonable outcome of this proceeding and as the Commission has not yet made a formal decision regarding contribution policies from Decision 2012-362 forward, a July 1, 2012 effective date would not constitute retroactive rate making. Devon submitted that both the Commission's March 11, 2013 letter and the fact the Decision 2013-325 approved a tariff on an interim refundable basis confirms this interpretation.³⁴⁹

605. Devon noted that, in past decisions, the Commission has approved the backdating of investment levels on the basis of evidence that customers may attempt to delay projects until the proceeding has been concluded.³⁵⁰ In this regard, Devon submitted that the current proceeding has heard ample evidence that such deferrals are occurring.³⁵¹

³⁴⁶ Exhibit No. 112.01.

³⁴⁷ Exhibit No. 361.02, Devon argument, paragraph 25.

³⁴⁸ Exhibit No. 361.02, Devon argument, paragraph 12.

³⁴⁹ Exhibit No. 361.02, Devon argument, paragraph 67.

³⁵⁰ Decision 2012-362, paragraph 197 (cited at paragraph 68 of Devon argument).

³⁵¹ Transcript, Volume 6, page 955 (cited at paragraph 68 of Devon argument).

606. In its argument, the UCA opposed Devon's position that the AESO's new investment policy should be applied retroactively to July 1, 2012. The UCA noted that Commission findings in Decision 2012-362 agreed with the UCA's position that changes to the POD cost function should be applied simultaneously for the purposes of setting both investment levels and setting Rate DTS and submitted that this approach helps to avoid misalignment between what a market participant receives in investment and the rate the market participant pays for services received.³⁵² The CCA also disagreed with the Devon proposal.³⁵³

607. In reply argument, the AESO disputed the submission in the argument of Devon³⁵⁴ that a July 1, 2012 implementation date for the implementation of revised investment levels as proposed in its evidence should not be considered to be retroactive rate making. The AESO submitted that Decision 2012-362³⁵⁵ and the Commission's March 11, 2013 letter in respect of the application of Access Pipeline Inc. for a review and variance in respect of that decision (Access R&V)³⁵⁶ both state that the contribution policies approved in Decision 2010-606 and Decision 2011-275³⁵⁷ remained in effect. The AESO further submitted that the contribution policy approved in these tariff decisions on a final basis until September 30, 2013, when an updated contribution policy was approved in Decision 2013-325. Accordingly, the AESO submitted that the Devon suggestion that the approval of its proposed approach with an effective date of July 1, 2012 should be rejected.³⁵⁸

608. In its reply argument, the UCA submitted that it is evident from Decision 2012-362 that the Commission did not approve the AESO's contribution policy with an effective date of July 1, 2012, or any other date. The UCA also disputed the assertion of Devon that the Commission's letter of March 11, 2013 had the effect of confirming that current maximum investment levels should be considered interim. The UCA submitted that the March 11, 2013 letter did not vary Commission determinations in Decision 2012-362, but did clarify that parties could seek retroactive implementation of the AESO's contribution policy in the context of the current proceeding. However, consistent with its position in argument, the UCA submitted that contribution policy changes should not be applied retroactively, because doing so would be inconsistent with the need for POD cost function changes and investment levels to be changed simultaneously.

609. In its reply argument, Devon responded to the AESO's argument that "market participants have already made decisions with respect to their project schedules with no anticipation of retroactivity."³⁵⁹ Devon asserted that the AESO's position is in conflict with the extensive discussion that the Devon panel had with Commission counsel regarding the effect of contribution policy changes on the Weasel Creek project.³⁶⁰ Devon submitted that this is clear evidence that customers do pay attention to contribution policy changes and will adjust dates in consideration of such changes. In respect of the AESO's request that contribution policy changes

³⁵² Exhibit No. 364.02, UCA argument, paragraphs 87-89.

³⁵³ Exhibit No. 371.02, CCA argument, paragraph 119.

³⁵⁴ Exhibit No. 402.02, the AESO reply argument references Devon argument paragraph 67.

³⁵⁵ Decision 2012-362, paragraph 197.

³⁵⁶ Exhibit No. 112.06, paragraph 7.

³⁵⁷ Decision 2011-275: Alberta Electric System Operator, Compliance Filing Pursuant to Decision 2010-606 and 2011 Tariff Update, Application No. 1607003, Proceeding ID No. 1074, June 24, 2011.

³⁵⁸ Exhibit No. 402.02, AESO reply argument, paragraph 63.

³⁵⁹ Exhibit No. 366.01, AESO argument, paragraph 230.

³⁶⁰ Transcript, Volume 6, starting at page 955.

arising from the 2014 tariff should be implemented by October 1, 2014, the Commission should at least take into account the delays in this hearing process that have created a delay in the issuance of the final decision. Given the potential for multi-million dollar effects on individual project costs, the Commission should consider the effect of the procedural delays that have been experienced when determining the implementation date for investment level changes.

610. In reply to the UCA, Devon submitted that while it agrees in principle with the UCA that investment policy and the DTS rate changes should be applied simultaneously, Devon noted that the AESO and other parties (including the UCA) supported changes that would have resulted in misalignment between the POD cost function and investment levels during the 2012 CCP proceeding. Given this, and given that the POD cost function recovers the embedded cost of all existing PODs while the investment function affects projects only in a few years, Devon submitted that misalignment for a short period of time is not unreasonable.³⁶¹

611. In response, the UCA noted that its support in the 2012 CCP reflected the fact that the AESO was proposing a material increase in investment levels. However, as the 2012 CCP was not approved by the Commission, there is no similar reason for the investment levels proposed by the AESO to be applied retroactively.³⁶²

Commission findings

612. The Commission notes that a request for a retroactive effective date was before the Commission in the 2012 CCP application proceeding. In Decision 2012-362, the Commission rejected this request, as set out in the following findings:

197. Because the Commission has not approved any changes to the AESO construction contribution policy in this decision, the current construction contribution policy approved in Decision 2010-606 and the 2011 tariff update approved in Decision 2011-275 remains in effect. Given this finding, consideration of the AESO's request for an effective date of July 1, 2012, is no longer an issue to be decided in this decision. However, the Commission considers that certain issues should be clarified for the purposes of the upcoming comprehensive tariff application.

198. The Commission, in the past, has permitted the AESO to implement a retroactive effective date in prior tariffs for construction contributions based on the AESO's submission that some market participants may attempt to delay projects until the proceeding has concluded, which could create inefficiencies and schedule changes that may impact transmission facility owners. However, in this application, the AESO stated that a change in the level of construction contribution will have little, if any, effect on the number or size of system access service requests it receives. Given this, parties are advised that for the purposes of the construction contribution policy that will be filed as part of the AESO's next comprehensive tariff application, the Commission will not approve an effective date that is set prior to Commission approval.³⁶³ [emphasis added]

³⁶¹ Exhibit No. 396.01, Devon reply argument, paragraphs 18-19.

³⁶² Exhibit No. 361.02, Devon argument, paragraphs 56-57.

³⁶³ Decision 2012-362, paragraphs 197 and 198.

613. However, the March 1, 2013 Access R&V raised the following grounds for review:

- (1) The AUC erred in law in failing to allow a change to the construction contribution policy after receiving clear and uncontested evidence from the AESO that the contribution policy levels failed to keep pace with increasing costs over time with the result that newer customers receiving service and new customers seeking to receive system access from the AESO are paying substantially more, or are being asked to pay substantially more, to obtain system access service than existing customers for the same level and nature of service.
- (2) The AUC erred in law in making a determination that a future panel of the Commission, in a future application to be filed by the AESO, could not consider whether it may be appropriate to determine an effective date for the change to the construction contribution policy that may be retroactive.³⁶⁴ [emphasis added]

614. In accordance with the Commission's March 11, 2013 ruling in respect of the Access R&V, the Commission panel has fully considered the evidence of Devon and other submissions in respect of proposed effective dates for contribution policy changes.

615. The Commission considers that the "problem of the investment cliff" arises as a consequence of adopting a significant increase in the investment coverage level. Consistent with its finding that in the event of a conflict between ensuring an efficient price signal and adhering strictly to intergenerational equity principles, ensuring an efficient price signal should take precedence, the Commission considers that the increased investment level arising from final approval of this tariff should not be extended retroactively to market participants that would have made decisions on the basis of approved tariffs in effect at the time.

616. Further to the findings above, the Commission hereby approves the changes to investment coverage levels approved in Decision 2013-325 on a final basis, effective October 1, 2013.

617. The Commission agrees with the AESO that going forward, changes in investment levels arising from the approval of contribution policy elements considered in the current application should be given effect concurrent with the final approval of the AESO's 2014 tariff. In this regard, the Commission notes that the AESO has been directed to revise certain aspects of its contribution policy that are to be considered in conjunction with the AESO's refiling application, pursuant to this decision. Accordingly, for greater certainty, the Commission considers that contribution policy changes arising from the AESO's 2014 tariff will not come into effect until the AESO's refiling application has been approved and an implementation date will be included in that decision.

6.3.5 Investment level update process

618. The AESO explained its proposal for updating investment levels within both comprehensive tariff applications and annual tariff updates in its response to AUC-AESO-040(d).³⁶⁵ In that response, the AESO indicated that it proposed to:

³⁶⁴ Exhibit No. 112.06.

³⁶⁵ Exhibit No. 109.01.

- continue to target investment coverage of 60 per cent over all projects in future comprehensive tariff applications, adjusting the multiplier as required to achieve that coverage
- update the average cost function in future comprehensive tariff applications, including by adding and updating projects in the connection project database
- update investment levels with inflation as part of annual tariff updates occurring between comprehensive tariff applications

619. Several sections of the Devon evidence take issue with the investment level update processes contemplated by the AESO.

620. In Section 5 of its evidence (entitled Calculation of Contribution Levels), Devon submitted that:

- Commission findings in Decision 2012-362 expressed a desire that the AESO's construction contribution policy should exert an economic discipline on siting decisions by sending price signals, reflective of the AESO's economics, to connecting customers³⁶⁶
- it agreed that a target investment coverage level is a fair mechanism to achieve a balance between intergenerational equity and the provision of effective price signals³⁶⁷
- fairness requires that the investment coverage level to be maintained at a consistent level across multiple GTAs
- the heavy Alberta transmission build has significantly affected the cost of customer connection projects³⁶⁸
- in the AESO's response to ACCESS-AESO-001, the costs of 16 greenfield connection projects included in the AESO's 2012 CCP application that had used costs determined at the proposal to provide service (PPS) stage had been updated by a total of over \$43.8 million, representing an increase of 12 per cent
- an AESO information request response³⁶⁹ suggests that an annual 10.08 per cent difference between the increase implied by the AESO's proposed inflation index (3.36 per cent) and the actual year-over-year project cost increase (about 13 per cent) implies a 28.92 per cent gap between escalated historic costs and current project costs
- customers taking service after a major tariff update could receive investment levels at a significantly higher level, thereby causing an "investment cliff," thereby violating the goals of intergenerational equity, commercial certainty, and regulatory stability

621. In light of the above noted considerations, the Devon evidence proposed that:

- the investment function should be updated annually as part of the AESO's annual tariff update
- the investment coverage level should remain consistent across multiple GTAs, and should fall or rise as substation costs fall or rise³⁷⁰

³⁶⁶ Exhibit No. 146.02, paragraph 31, citing Decision 2012-362, paragraph 31.

³⁶⁷ Exhibit No. 146.02, paragraph 31, citing Decision 2012-362, paragraph 34.

³⁶⁸ Exhibit No. 146.02, paragraph 31, citing Decision 2012-362, paragraph 39.

³⁶⁹ Exhibit No. 109.01, AUC-AESO-021(a).

³⁷⁰ Exhibit No. 146.02, paragraph 48.

622. Section 6 of the Devon evidence (entitled Updating the DTS Average Cost Function) discussed its proposal that the average cost function should be updated as part of the annual DTS rate update process. Devon noted that the Commission found in Decision 2012-362 that changes to the average cost function should be applied simultaneously for both the determination of investment levels and the establishment of Rate DTS and accordingly directed the AESO to refile its proposed changes to the average cost function in its next comprehensive tariff application.

623. Devon noted that as the cost function is based on the connection dataset discussed in its evidence, updating the average cost function is an entirely mechanical process. As such, Devon submitted that the cost function should be updated annually, as part of the annual AESO tariff update process.

624. However, Devon submitted that as the DTS average cost function is required to allocate the embedded cost of existing facilities installed over a number of decades, it is entirely appropriate that all available facility cost data be used to calculate the average cost function. Conversely, Devon submitted that since investment levels are forward-looking and a construction contribution is paid for service at a point in time and is not subject to change, the investment function should use the most current data to provide effective price signals to customers contemplating alternative connection facilities.³⁷¹

625. In argument, the AESO noted that it had provided a summary of its proposed process for updating investment levels as part of both comprehensive and annual update applications in its response to AUC-AESO-040(d), which noted that:

- it intends to continue to target investment coverage of 60 per cent over all projects in future comprehensive tariff applications
- it expects to continue to update the average project cost function in future applications, which will include the addition and updating of projects in the project cost database
- between comprehensive tariff applications, it intends to continue to update investment levels to reflect inflation as part of annual tariff updates

626. The AESO submitted that its proposed approach reflects the following finding in Decision 2012-362:

189. In past ISO tariffs, investment coverage was determined based on all available connection project cost information, the same dataset used to estimate the average cost function. Ordinarily, as part of a comprehensive tariff application, the dataset would be updated with new connection projects and the most recent cost data for the existing connection projects. In this way, the higher cost projects increase the overall average cost, but the increase would be dampened by older, lower cost connection projects (even though they are escalated by inflation). The Commission has some concern with moving away from this approach. The Commission agrees that investment coverage should recognize the changes to service characteristics, functionality, and standards that occur over time, but at the same time investment coverage should not incent increasing costs due to increased radial line requirements, transmission voltage level, substation configuration, varying geography or unique construction and environmental conditions.

³⁷¹ Exhibit No. 146.02, paragraphs 68-69.

The Commission considers that the regular updating of connection project data that occurs as part of a comprehensive tariff application should sufficiently capture the changes to service characteristics, functionality, and standards that occur over time. The update to the cost data and to the average cost function will also serve to rectify any potential “investment cliffs” as evidenced between 2010 and 2011.³⁷²

627. The AESO submitted that its proposal to assess investment coverage using the full connection project dataset within comprehensive tariff applications provides a balance between the following considerations:

- reflecting recent cost data
- dampening the effect of unusual or temporary increases in project costs
- avoiding undue upward pressure on rates due to increasing investment levels
- providing consistency and stability to avoid potential investment level cliffs

628. The AESO submitted that while Devon suggests that its proposed approach for updating contribution levels would be a mechanical process, the Devon proposal includes an update of the POD cost function. However, as evidenced by the attention directed at the POD cost function during the current proceeding, the AESO submitted that the update process is not entirely mechanical, as suggested by Devon. Contrary to the submission of Devon, moving away from the current approach and implementing more complex updates of the POD cost function will not reduce the regulatory burden.³⁷³ In particular, the AESO noted that it had explained that updating the project cost dataset to prepare its ACCESS-AESO-001 response required 80 person-hours of effort. Further, the AESO submitted that annual updates of the connection project database would likely require twice the effort (i.e., 160 person-hours).³⁷⁴ Given this, the AESO submitted that a comprehensive update process could not be considered to be either mechanical or routine.³⁷⁵

629. In argument, Devon submitted that its proposal to update annually the project cost dataset on a five-year rolling average to determine investment levels is simple, fair, and administratively efficient and makes use of the most recent and best cost information available.³⁷⁶

630. Devon submitted that the AESO approach of updating its tariff every three years and applying annual inflation adjustments has not kept pace with the actual cost increases being experienced for transmission connection projects.

631. Devon submitted that the effort that would be involved in undertaking annual updates is insignificant in relation to the tens of millions of dollars in contribution policy changes that could be anticipated. Furthermore, considering that project costs are increasing at an average rate of 13 per cent per year, the anticipated gap between actual project costs and the level of the investment function would give rise to a significant investment cliff, since it would strongly encourage market participants to delay project activities to await higher investment levels.

³⁷² Decision 2012-362, paragraph 189 (referenced at paragraph 234 of AESO argument).

³⁷³ Exhibit No. 366.01, AESO argument, paragraph 38.

³⁷⁴ Exhibit No. 366.01, AESO argument, paragraph 166 (references Transcript, Volume 2 at page 176).

³⁷⁵ Exhibit No. 366.01, AESO argument, paragraph 167.

³⁷⁶ Exhibit No. 361.02, Devon argument, paragraphs 8-9.

Devon submitted that this result is a recipe for intergenerational inequity and would be profoundly unfair to market participants caught on the wrong side of the line.³⁷⁷

632. The CCA did not support the adoption of the annual update mechanism proposed in the Devon evidence, arguing that this approach would not be consistent with providing appropriate price signals that are stable over time. The CCA also submitted that substituting annual updates in place of the inflation index mechanism for escalating investment levels is not conducive to regulatory efficiency and does not provide incentives for efficiency, as was intended in the decision to use that mechanism.³⁷⁸

633. The UCA also opposed the Devon proposal for annual update of project database, POD cost function and structure of the POD charge. In support of this view, the UCA noted that:

- the AESO indicated that it would take 160 person-hours of effort to verify an update to the project cost database
- updating the project cost database is not a mechanical function
- it is apparent from the current proceeding that any update to the database would be contentious.³⁷⁹

634. In reply argument, Devon responded to the AESO's argument that an annual update process using current cost data would not be mechanical and argued that the debates of parties primarily relate to the proper approach to determining the POD cost function. Once these issues are resolved, no further debates of principles are contemplated in the annual update process.

635. In response to the UCA concerns that annual update project cost data cannot be verified easily, Devon submitted that, as the AESO tracks connection projects on a daily basis, a large amount of data will be publicly available. Furthermore, while an annual update process will require effort, if the AESO does not currently have a robust internal process for compiling current project cost information, the establishment of annual update process may encourage the AESO to create a central cost database, thereby minimizing any extraordinary effort that may be required to gather the data. Devon agreed with the UCA's view that changes to the rate structure should only occur as part of a GTA, and submitted that under its proposal, only the POD cost function would change on an annual basis while the rest of Rate DTS would remain unchanged.

636. Finally, Devon submitted that because stability was not a principle proposed by the AESO or supported by stakeholders in the 2012 CCP proceeding, the CCA's argument that annual updates of the POD cost function would be contrary to the goal of providing a stable price signal was without merit.

Commission findings

637. The Devon proposal for investment levels to be updated annually on the basis of an assessment of investment coverage against a five-year dataset of connection projects reflects the view of Devon that a five-year dataset is a better dataset for assessing the current costs of

³⁷⁷ Exhibit No. 361.02, Devon argument, paragraphs 35-36.

³⁷⁸ Exhibit No. 371.02, CCA argument, paragraph 114.

³⁷⁹ Exhibit No. 364.02, UCA argument, paragraphs 112 to 116.

connection projects. However, as discussed in Section 6.3.3.1 of this decision, the Commission has not accepted this rationale.

638. In addition, the Commission accepts the evidence put forward by the AESO in which the AESO claimed that a significant amount of effort would be required on the part of the AESO to prepare a dataset update of the quality required to be included in an annual AESO tariff application.

639. Furthermore, even if the process to refine the project cost dataset could be developed to the point that it could be considered “mechanical,” as suggested by Devon, due to the significance of changes in investment levels to different market participants, the updated dataset could be a matter of significant contention in a future annual tariff update proceeding.

640. In contrast, continuing the current annual investment update process approved in Decision 2010-606 should be comparatively non-contentious and provide reasonably predictable results. The Commission considers the predictability of outcomes from the annual update investment process is a significant advantage of the current annual investment level update framework.

641. Accordingly, the Commission approves the annual update framework as described in the AESO’s response to AUC-AESO-040(d).

642. The Commission notes that the escalator described in Section 5.3.2 of this decision was approved for use in updating the original cost of connection project in the project dataset to current year values.

6.4 Payment in lieu of notice

643. In the application, the AESO proposed to continue its requirement that a market participant must provide five years notice of a reduction or termination of service.³⁸⁰ Alternatively, for a customer taking service under rate DTS, the customer could make a payment in lieu of notice (PILON) calculated by the AESO as the present value of the difference in bulk system and local system charges that would be attributed to the service with and without the reduction or termination of contract capacity during the notice period. As no bulk system charges would be payable upon the reduction in capacity, the PILON would only be applicable to regional system charges otherwise payable.

644. The ADC submitted that although the filed AESO tariff reflected the TFO revenue requirement, it did not solely reflect the cost to serve the current DTS customers over the next five-year planning horizon. Instead, it included costs to serve future generations of Alberta customers over the next several decades. As such, the five-year notice and the PILON based on the 2014 GTA DTS rate was not a reasonable proxy for any stranded investment that may result from a customer reducing its DTS contract capacity.

645. The ADC recommended that the notice provisions be eliminated or reduced to six months where a customer has been served for 20 years. For customers that have taken service for less than 20 years, any PILON should be based on demonstrated actual costs of unrecovered

³⁸⁰ Exhibit No. 16, Appendix N, page 37, Section 9.3 of proposed T&C and the tariff application, pages 68-69.

investment in facilities serving the requesting customer and this total amount should decline in correlation with the number of years they have taken service.

646. The ADC maintained that the notice could not be based on cost causation and the AESO could not support the notion that the PILON was related to cost of service. Rather, it was simply an incentive for customers to give notice to allow the AESO to plan for changes in its load characteristics over a five-year planning period.³⁸¹ The ADC submitted that in the last hearing, and in the language of the tariff itself, the AESO had stated the PILON represented “a share of fixed system costs incurred to accommodate the contract capacity of a market participant over the five-year planning horizon of the transmission system,”³⁸² which was, in essence, recovery of stranded transmission system costs. The ADC stated the AESO was not making this same claim in the current proceeding and noted that the AESO’s witness, Mr. Martin, stated, “Our goal is to get the notice ... one way to get the notice is to put some kind of incentive there or some penalty ... We think five years is a reasonable horizon over which we need customer information to be able to plan the system.”³⁸³

647. The ADC stated that a survey of other North American jurisdictions showed that limited, if any, notice or PILON was required in the event of a reduction or termination of capacity.³⁸⁴ The transmission rates in all of these jurisdictions, including Alberta, were regulated. The transmission owners received the revenue requirement found reasonable regardless of what happened in the power market. The regulatory mechanisms protect the transmission owners, and the expected growth in customer count and load built into rates protected future customers from the negative effects caused by the loss of a customer.

648. The ADC also argued that the PILON was not equitable across generations of customers, and stated that current transmission charges allow for recovery of transmission capacity that is in excess of the demands of current customers. Hence, rates paid by current transmission customers include capacity that was not needed for their service demand. Without the PILON, the transmission system really would not change and future customers would continue to need the existing capacity on the system. The notion of mitigating cost effects on future customers placed a blind eye to the cost effects on current customers. If future customers are paying for more capacity because current customers leave, then they would have the same price burden as do current customers. As such, the PILON did not maintain equity between generations of customers.

649. Finally, the ADC argued that the reasonableness and balance of a five year notice period, particularly for customers that have already been taking service from the AESO or its predecessor for 20 years, was dubious at best, especially considering that when most of those customers originally took service, the five year notice provision did not exist.³⁸⁵ At the time those customers originally took service more than 20 years ago, the structure of the transmission system was comparable to what it is now. However, it preceded the significant build-out of the

³⁸¹ Transcript, Volume 3, pages 469-470.

³⁸² Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Application No. 1605961, Proceeding No. 530, December 22, 2010, page 91; and ISO Tariff – Section 9, subsection 5(3).

³⁸³ Transcript, Volume 3, page 470.

³⁸⁴ Exhibit No. 141.01, ADC Chekerda evidence, pages 7-10.

³⁸⁵ Transcript, Volume 4, page 560.

transmission system to accommodate expected large annual increases in load growth.³⁸⁶

Ms. Chekerda testified, on behalf of the ADC, that direct served customers cannot know with certainty in five years' time whether or not their DTS contract requirements will change.³⁸⁷

650. Therefore, many direct connect customers are not able to give five years notice of load changes. As such, the five-year notice provision cannot be justified based on value added to the planning process.

651. The AESO noted that the current notice provisions have been in effect, with regulatory approval, since the 1999-2000 GTA of ESBI Alberta Ltd. (the predecessor of the AESO). The AESO referenced Decision 2000-1, in which the board stated:

The Board considers that five years is well within the planning horizon of any capital intensive industry and that industrial customers should be able to accommodate this provision within their planning processes. The Board considers that the five year provision, as a general principle, provides a balance between flexibility for customers and the need to recover any stranded system costs from remaining customers.³⁸⁸

652. The AESO also stated that this issue has been raised in subsequent proceedings with the same result. The AESO submitted that the prior decisions clearly demonstrate that the ADC's concerns with the AESO's notice and PILON provisions have been thoroughly and repeatedly examined in previous proceedings. The AESO submitted that no new concerns have been raised in this proceeding and that the AESO's proposed continuation of the existing notice provisions should be approved.

653. With respect to the five year notice period, the AESO explained in cross examination³⁸⁹ that it was seeking five years notice from customers to allow it to plan the transmission system as effectively as possible because five years is generally representative of the length of time it takes to plan and develop a transmission system development. Less than five years notice may reduce the AESO's ability to plan effectively the transmission system and "to ensure that the right facilities are built and no more facilities are built than are needed."³⁹⁰ The AESO stated that, "what [it] really wants is advance information from customers that [it] can use to influence [its] long-term plan."³⁹¹

654. The AESO noted the ADC's assertion that "there are no industrial customers that can predict with certainty 5 years in advance whether or not their electricity requirements will be consistent with their current DTS contract."³⁹² However, the AESO submitted that during cross-examination by the ADC, Mr. Martin testified that many market participants commit for 20 years of capacity when contracting for a new system access service or for an increase to an existing system access service.³⁹³ The AESO further explained that market participants actually do provide the AESO with five years notice for decreases or termination of contract capacity and

³⁸⁶ Transcript, Volume 3, page 414 and Transcript Volume 4, pages 560-563.

³⁸⁷ Transcript, Volume 4, page 547-548.

³⁸⁸ Decision 2000-1, page 216.

³⁸⁹ Transcript, Volume 1, pages 135-139.

³⁹⁰ Transcript, Volume 1, page 136.

³⁹¹ Transcript, Volume 3, page 470.

³⁹² Exhibit No. 141.01, page 11.

³⁹³ Transcript, Volume 1, pages 134-135.

several, including the ADC, requested a long-term projection of transmission rates so that they could make long-term plans for their connections to the transmission system.³⁹⁴

655. The AESO explained that the regional charge was not based “on specific regional facilities serving a customer” but instead “is an average charge reflecting the service a market participant receives.”³⁹⁵ The AESO added:

What the payment in lieu of notice calculation tries to do is give a simple and average calculation of the impact of a market participant on the regional system overall. It also tries to reflect that the regional system is generally a very networked system So it's very difficult to identify specific regional facilities and attribute them to specific services.³⁹⁶

656. The AESO considered the financial effect of a market participant on the regional system to be the share of fixed system costs incurred to accommodate the contract capacity of that market participant.

657. Finally, in response to the ADC’s argument that the PILON was not equitable across generations of customers because “rates paid by current transmission customers include capacity that is not needed for their service demand,”³⁹⁷ the AESO submitted that this aspect of embedded cost rate making was not new, and noted that the nature of large capacity transmission additions is that they are lumpy. The AESO submitted that additional capacity above the specific demands of current market participants was a characteristic of the transmission system that has existed for decades across several generations of market participants. Accordingly, no intergenerational inequity arose as a result of current rates including such capacity.

658. The CCA supported the AESO and submitted that regional facilities are different from bulk system facilities in that the degree of diversity on the regional system is less when compared to the bulk system. It was for this reason that billing capacity based on non-coincident peak demands and ratchets is applied to regional facilities. This implied a greater degree of customer specificity of regional facilities which, in turn, suggested that a greater lead time for costs attributable to any customer who leaves the regional system without notice is required in order to serve other customers through the planning process.³⁹⁸

659. The CCA argued that the ADC’s proposal to consider regional assets as some form of dedicated assets associated with a departing customer is not consistent with how the planning of regional system additions occurred. The AESO explained in its rebuttal evidence that on the shared regional system, where multiple customers are served through transmission facilities constructed at different times, it is not practical to attempt to attribute specific costs to individual services.³⁹⁹ As such, the CCA submitted that the AESO’s proposed 60 months PILON appeared to strike a reasonable balance between the recovery of costs attributable to potentially stranded regional assets attributable to departing customers and the need for the planning process to recognize how the departure of the customer needs to be incorporated into future planning. The

³⁹⁴ Transcript, Volume 1, page 159.

³⁹⁵ Transcript, Volume 1, page 141.

³⁹⁶ Transcript, Volume 1, pages 148-149.

³⁹⁷ Exhibit No. 358.01, ADC argument, page 24.

³⁹⁸ Exhibit No. 371.02, CCA argument, page 39, paragraph 107.

³⁹⁹ Exhibit No. 264.02, paragraphs 5-6.

CCA recommended that there be no reduction in the existing 60 months of regional demand charges as the determinant for the PILON.

660. The UCA also supported the AESO's five year PILON. The UCA argued that there was always unrecovered investment if a customer reduced load without notice. Transmission facilities are depreciated over periods much longer than 20 years, so there would inevitably be unrecovered investment after just 20 years. Furthermore, the UCA noted that transmission facilities were continually maintained and replaced as required, so that it was highly unlikely that the net book value of the transmission facilities serving a customer would ever be zero.

661. Under the current tariff, there are circumstances where the AESO could waive or reduce payments. The UCA stated that other than with these exceptions, customers who reduce load should be required to provide sufficient notice to the AESO to enable the AESO to adjust its transmission development plans. If a customer reduces load without notice, there was no immediate reduction in the fixed costs of the transmission system.⁴⁰⁰ In the absence of the PILON, those stranded fixed costs would be transferred to the remaining customers until such time as the AESO can adjust its transmission development plans. The UCA stated the length of time it took the AESO to modify transmission system development in response to the unexpected loss of a large load on the system was important.⁴⁰¹ The UCA noted the AESO's assertion that it typically took three years from receiving a request for system access service to energizing the service, and longer if system development was needed.⁴⁰²

662. The UCA asserted that the PILON was not a penalty for failing to provide notice. Rather, the purpose of the notice provision was to provide the utility with sufficient time to alter its development plans to ensure that stranded fixed costs were not transferred to the remaining customers.

663. The UCA also disagreed with the ADC claim that when most of the current customers originally took service, a five-year notice period did not exist.⁴⁰³ In Decision 2000-1, the board denied Dow's request to relax the five-year notice requirement that existed at that point.⁴⁰⁴ The UCA submitted that as the five-year notice requirement was in place prior to 1999, it has been in place for a minimum of 15 years.

664. The DUC supported the position of the ADC. It maintained that the PILON was not based on cost causation and should be eliminated from the AESO's tariff. In its view, the PILON was a blunt instrument that penalized existing customers who may not be imposing any incremental costs when decreasing their reliance on the transmission system. If the AESO wanted information on when customers could be reducing their reliance on the transmission system for planning purposes, then there were more effective ways to obtain the information. For example, in areas where transmission upgrades are planned (as per the long-term transmission plan), the AESO could ask its customers in the potentially affected area what their future plans were. The perceived discipline the AESO was seeking by imposing the PILON was not working.

⁴⁰⁰ Transcript, Volume 4, page 510, line 5-19.

⁴⁰¹ Exhibit No. 364.02, UCA argument, page 18, paragraph 103.

⁴⁰² Exhibit No. 364.02, UCA argument, page 18 refers to Transcript, Volume 1, pages 137-138, lines 18-10.

⁴⁰³ Exhibit No. 358.01, ADC argument, page 25.

⁴⁰⁴ Decision 2000-1, page 216.

The clear evidence from the AESO customers is that they cannot predict with accuracy five years out if their load requirements will materially change.⁴⁰⁵

665. In reply argument, the ADC stated the significant level of transmission system asset build-out has not been disputed in this case. However, the concept of recovering from all current customers the shared costs of such an unprecedented level of long-term system assets did not justify the need for a five year notice period for capacity reduction or termination. The ADC argued that the true position of the AESO was that the PILON existed to elicit a behavioral response from customers.⁴⁰⁶ This evidence cast doubt on the justification of the current PILON and notice provisions, with similar doubt cast on any tariff rate provision that was not clearly linked to cost of service principles.

666. ADC concluded that following cost of service principles with regard to the PILON and notice provisions was imperative. Price signals to customers occurred whether in the form of rate charges or terms and conditions of service. AESO customers, whether departing or remaining on the system, should not be saddled with costs not attributable to their load. As such, the ADC's proposal that PILON charges and stranded cost recovery should be based on demonstrated actual costs of unrecovered investment, and the notice provision should be eliminated or reduced to six months where a customer has been served for 20 years or more, should be approved.

Commission findings

667. The ADC's opposition to the five-year notice and the PILON and its own recommendation that the notice provisions be eliminated or significantly reduced is generally premised on its position that the PILON is intended to represent compensation for past investment and is a proxy for stranded investment that may result from a customer reducing its DTS contract capacity.

668. According to the AESO, these premises are incorrect. The purpose of the PILON, according to the AESO is to assist the AESO in the planning of transmission investment to avoid over building the transmission system. In order to be effective in this respect, the notice period or payment in lieu of notice must be of sufficient size to ensure that customers are encouraged to represent their future capacity requirements as accurately as possible. The Commission accepts the AESO's evidence and finds that, in order to plan the transmission system effectively, reasonable notice that a customer will be reducing its DTS contract capacity is required, or a PILON is required in lieu of adequate notice.

669. In arriving at this determination, the Commission considered Section 33(1) of the *Electric Utilities Act* which states that the AESO "must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable, and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements." As the sole provider of system access service on the transmission system,⁴⁰⁷ the AESO has a duty to plan the transmission system and connect new customers.

⁴⁰⁵ Transcript, Volume 4, pages 547-548.

⁴⁰⁶ Exhibit No. 358.01, ADC argument, page 23.

⁴⁰⁷ Section 28 of the *Electric Utilities Act*.

670. If no reasonable notice is provided for the AESO to forecast its transmission investments, then the AESO has no choice but to assume that current customers will continue to require their current service or load. Because the AESO must develop a transmission system to satisfy future demand, the costs of which are paid for by all load customers in Alberta, the Commission finds the PILON to be a necessary and reasonable tool to mitigate the risk of building excess or unused capacity in the future and the attendant costs.

671. Mr. Martin, on behalf of the AESO, testified that a notice period is necessary in order for the AESO to plan the transmission system effectively. Mr. Martin further explained that the PILON reflects the value of the service a customer received from the system. The regional system is a networked system and it is therefore not possible to attribute specific assets to specific customers, as suggested by the ADC. Further, the assets employed in the provision of service are sized to meet the capacity and reliability needs of customers.⁴⁰⁸ These assets can have lives of 40 or 50 years, well beyond the 20 year contract term referenced by the ADC. The Commission also agrees with the position of the CCA⁴⁰⁹ that because billing capacity is based on non-coincident peak demands and ratchets are applied to regional facilities, greater lead time for costs attributable to any customer who leaves the regional system without notice is required in order to serve other customers through the planning process.

672. It is apparent that customers receive a service beyond the specific assets dedicated to an individual customer. The Commission considers that transmission service requires a reasonable planning horizon and that customers should be responsible for that portion of the cost of the service and the assets employed to meet the capacity requirements of the customer. With respect to the length of notice required, the Commission notes that, in Decision 2005-086,⁴¹⁰ the board determined that a two-year notice period was reasonable for the Fortis distribution system. In setting the notice period, the board considered that a PILON period should result in an appropriate balance of cost and risks that considers the interests of the existing customer, other remaining customers and the distribution utility. The board determined the primary purpose of a notice period is to provide an appropriate level of revenue certainty and rate stability for a distribution wires company and its remaining customers. The Commission considers these factors to be important criteria for determining the reasonableness of a PILON period for a distribution utility.

673. The Commission considers that the AESO would require a longer lead time to plan a transmission system change than would be required to plan a distribution system change. The Commission notes that the ADC witness, Mr. Olson, testified that it would take two years to plan and implement a load reduction project.⁴¹¹ Mr. Martin testified that it would typically take three years to energize a service from the date a request for system access service is received, and longer if system development was needed.⁴¹² Mr. Martin also testified that the AESO was seeking a five year notice period as this is the period necessary to plan the transmission system

⁴⁰⁸ Transcript, Volume 3, page 428.

⁴⁰⁹ Exhibit No. 371.02, CCA argument, page 39, paragraph 107.

⁴¹⁰ Decision 2005-086: FortisAlberta Inc., 2005 Distribution Tariff, Payment in Lieu of Notice, Application No. 1371998, August 2, 2005.

⁴¹¹ Transcript, Volume 4, page 549.

⁴¹² Transcript, Volume 1, pages 137-138.

effectively to ensure that the right facilities are built and no more facilities are built than are needed.⁴¹³

674. On the basis of this evidence, the Commission finds that the minimum period of notice is no less than three years, if at a minimum the time necessary to plan and energize the system is considered. However, as the Commission has also determined, the purpose of the PILON is to provide the AESO with reasonable assurance that when planning for the transmission system, existing customers will still require their current capacity in the future. The Commission accepts the testimony of Mr. Martin that the five-year period is required for adequate planning of the transmission system. The Commission accepts that the required notice period allows the AESO to plan the system more effectively than would otherwise occur under a shorter notice period. Accordingly, the Commission finds that a shorter notice period or a smaller payment in lieu of notice may not provide sufficient incentive to customers to provide accurate and timely notice to the AESO. For the foregoing reasons, the Commission finds that the AESO's proposal to continue its requirement that a market participant must provide five years notice of a reduction or termination of service is reasonable and approves the continuation of that requirement.

7 Deferral account and tariff update processes

7.1 Tariff update frequency and process

675. In argument, the AESO noted that it had explained to Commission counsel that, in conjunction with less frequent comprehensive tariff applications, annual tariff updates ensure that the AESO's rates reasonably reflect the AESO's revenue requirement in each year.

676. The AESO noted that while having annual tariff updates and Rider C both help to minimize deferral account balances, they are distinct approaches. The AESO also noted that it had explained in its response to AUC-AESO-028(c) that, if tariff updates were discontinued, the AESO would likely file comprehensive tariff applications more frequently to ensure that base rates remain aligned with annual revenue requirements.

677. In its argument, the DUC submitted that the current three-year tariff review with annual update process should be continued. However, the DUC submitted that the AESO should initiate its tariff review process sooner so that the tariff is updated in a more timely manner. For example, the DUC submitted that while the 2014 tariff is likely to be implemented in Q3 of 2014, it is based on 2012 and earlier data. In this regard, the DUC submitted that the AESO's cost of service study could have commenced six months sooner and noted that the 2013 tariff update was not implemented until October 1, 2013.

678. The ADC submitted that it favoured a frequent tariff update process to minimize deferral account balances. The ADC expressed concern that certain members have received material adjustments to their annual DTS bill through the deferral account reconciliation process. The ADC noted that in most cases, the reconciliation resulted in refunds of millions of dollars. The ADC submitted that, as refunds bear no interest and take working capital out of ADC member businesses, having large refunds is undesirable.

⁴¹³ Transcript, Volume 1, page 136.

Commission findings

679. The Commission's interest in this matter arose primarily from the Commission's inquiry into whether the tariff update could be completed without the need to file an application. In particular, the Commission had an interest in understanding whether a redesign of Rider C, to more closely match the DTS rate design could make the tariff update process unnecessary.

680. For the reasons discussed in Section 7.3 of this decision, the Commission has determined that it will not require the AESO to revise its Rider C design at this time. Additionally, the Commission is satisfied that the annual tariff update process is well understood by parties and the regulatory process is not overly burdensome for parties. Accordingly, the continuation of the annual tariff update process between comprehensive tariff applications is approved as filed.

681. The Commission continues to support the AESO's current practice of filing comprehensive tariff applications on a three-year cycle. The Commission considers this approach to be reasonable because the Commission recognizes that the development of a comprehensive tariff application requires a major undertaking by the AESO that involves substantial consultation. In addition, the Commission considers that a three-year major update cycle provides stability to market participants on a number of issues that might otherwise be contested every year.

7.2 Deferral account practices

682. In Decision 2011-049,⁴¹⁴ issued in respect of the AESO's application for approval of its reconciliation of deferral account balances for the year 2009, the Commission set out the following direction:

211. ... Accordingly, the Commission directs the AESO to consult with stakeholders for the purpose of determining whether AESO deferral account balances related to years that have already [been] subject to at least one reconciliation may be projected forward rather than being precisely re-reconciled. For greater certainty, the AESO is specifically directed to consider whether prior year AESO deferral account reconciliations arising from Commission decisions in respect of TFO tariffs should be re-reconciled or projected forward....⁴¹⁵

683. The AESO indicated that its response to this directive was set out in Section 6.3.6 of the application.⁴¹⁶ In that section, which is entitled Deferral Account Adjustment Rider C, the AESO primarily discussed the potential effect of possible changes in the design of Rider C on the need for, or number of, deferral account reconciliations. However, in Section 6.3.6, the AESO indicated that it had also reviewed whether improvements to the deferral account process could be implemented to reduce the effects of timing differences and forecast variances. The AESO indicated that its review did not identify any changes that would reduce the magnitude of reconciliation charges and credits to individual market participants while maintaining the approach of the existing retrospective deferral account reconciliation process.

⁴¹⁴ Decision 2011-049: Alberta Electric System Operator, 2009 Deferral Account Reconciliation, Application No. 1606095, Proceeding ID No. 589, February 10, 2011.

⁴¹⁵ Decision 2011-049, paragraph 211.

⁴¹⁶ Exhibit No. 26, application.

684. In information request AUC-AESO-030, the Commission asked the AESO to describe what, if any, changes the AESO proposed to make to its deferral account reconciliation processes to address the Commission's concern that the number of reconciliations should be limited. In its response to this question, the AESO indicated that it had brief discussions with stakeholders on this matter in consultations held on April 3, 2012 and November 20, 2012. Although it had anticipated further consultations, these did not take place due to the emergence of other priorities during the course of the AESO's preparation of the application. However, the AESO noted that, in prior consultations, the AESO had held meetings with the representatives of small consumers and distribution system owners that focussed on whether or not the AESO should use a retrospective re-reconciliation of, or a prospective forward projection in respect of, TFO tariff adjustments.

685. The AESO noted that small and mid-sized consumers served through distribution utilities are charged on a prospective basis for AESO deferral account reconciliations, irrespective of whether the reconciliations are completed on a prospective or retrospective basis. However, direct connect market participants billed for system access by the AESO are more directly affected by the choice of reconciliation methodology and the AESO understands that these market participants generally support the continuation of the retrospective approach.

686. In argument, the AESO noted that stakeholder participation in annual AESO deferral account reconciliation proceedings has tended to dwindle over the years, and suggested that reduced participation may indicate that market participants are satisfied with the current approach. The AESO further noted that its four most recent deferral account reconciliations have been approved as filed.

Commission findings

687. The Commission notes that while the AESO did not extensively discuss potential changes to deferral account reconciliation processes in the application, these matters were examined through Commission counsel questions put to the AESO panel during the oral hearing and through information requests.

688. The Commission accepts the AESO's suggestion that a trend of less active participation in deferral account reconciliation proceedings may be a sign that, for the most part, the deferral account processes currently in effect are reasonably accepted by market participants.⁴¹⁷

689. During the oral hearing, Commission counsel discussed whether the AESO's current practice of ensuring the TFO wires costs are fully reconciled to the production years to which they relate may be at cross-purposes with a proposal to smooth transmission rate increases by using a rate mitigation deferral account to be administered by the AESO. The Commission accepts the AESO's submission that any potential conflicts should be addressed as and when decisions on rate mitigation measures are made.⁴¹⁸

690. Commission counsel also discussed the advantages and disadvantages of applying a cut-off to the number of years that a specific deferral account should be subject to in a

⁴¹⁷ Transcript, Volume 3, page 370.

⁴¹⁸ Transcript, Volume 3, pages 361-362.

re-reconciliation of any material variances that may arise.⁴¹⁹ With respect to this issue, the Commission accepts the AESO's explanation that there may be an appetite to apply cut-offs to prior years that have been reconciled more than once, so that small variances that may arise can be projected forward. However, the Commission acknowledges and accepts the AESO's explanation that there may be some risk that, once prior-year variances are projected forward rather than re-reconciled, it may be difficult to reverse if a more material variance is identified.⁴²⁰

691. In view of the above, the Commission makes no specific directions to the AESO in respect of deferral account processes, except as set out in Section 7.3 of this decision.

7.3 Rider C design

692. In Decision 2010-606, in respect of the AESO's 2010 tariff application, the Commission issued the following direction in respect of the design of Rider C:

315. In consideration of the above, the Commission remains interested in understanding whether potential changes in the design of Rider C could contribute to a reduction in the frequency of tariff update applications and/or deferral account reconciliations. Accordingly, the Commission directs the AESO to discuss proposed changes to the design of Rider C no later than its next GTA unless already addressed in another context such as in relation to a future AESO deferral account reconciliation application.⁴²¹

693. In addition, the Commission issued a direction at paragraph 211 of Decision 2011-049, which discussed the relationship between deferral account reconciliation processes and Rider C, as set out below. They dealt, in part, with the design of Rider C:

211. ... The Commission further directs the AESO to discuss whether changes in the design of Rider C could be made for the purposes of minimizing the need to reconcile AESO deferral account balances. The AESO is directed to provide a report on its discussions with stakeholders in respect of this matter at the time of its next major GTA.⁴²²

694. The AESO addressed these directives in Section 6.3.6 of the application. In that section, the AESO indicated that it had investigated changes to the design of Rider C and concluded that no changes were warranted at this time.

695. The AESO noted that in Decision 2010-606, the Commission took note of a concern expressed by an intervener that the energy based denomination of Rider C may contribute to periodic misalignments between the amounts that AESO customers should pay and the amounts they are required to pay for services under the tariff.⁴²³ The AESO attributed this concern to a perception that charges and refunds applied to individual market participants may appear large relative to the net amount of the revenue requirement shortfall or surplus reconciled in a deferral account reconciliation application for a particular year.

⁴¹⁹ Transcript, Volume 3, pages 363-370.

⁴²⁰ Transcript, Volume 3, page 367.

⁴²¹ Decision 2010-606, paragraph 315.

⁴²² Decision 2011-049, paragraph 211.

⁴²³ Decision 2010-606, paragraph 314.

696. The AESO indicated that it investigated potential causes of large individual deferral account charges or refunds and determined that this outcome may be caused by:

- different bases for Rider C and DTS rate components
- timing differences between Rider C collections and refunds as compared to production-month deferral account reconciliations
- variances from forecasts of costs and revenues

697. In consideration of these potential causes, the AESO recalculated the 2011 deferral account reconciliation assuming Rider C had been charged or collected as a percentage of each rate component rather than as a \$/MWh amount. The AESO found that while different market participants were affected, using a percentage-based Rider C did not significantly reduce the magnitude of charges and refunds arising from the reconciliation. Furthermore, after examining other potential improvements to the deferral account process, there were no straightforward changes it could make to Rider C that would materially reduce the overall magnitude of the reconciliation charges and refunds.

698. In argument, the AESO noted that it advised Commission counsel during the oral hearing that it would not be overly helpful to modify Rider C from its current simple and well understood form if doing so did not achieve the desired outcome. However, the AESO proposed to monitor future deferral account reconciliations to gain further insight into the causes of large refunds or charges to individual market participants and to propose changes to Rider C in future tariff applications, if warranted.

699. The AESO submitted that possible considerations that could trigger changes to Rider C include:

- trends in the magnitude of deferral account balances
- refunds and charges between market participants as part of deferral account reconciliations
- re-examination of effects through simulation of different designs
- stakeholder feedback

700. In their respective argument submissions, both the DUC and the ADC submitted that the Commission should direct the AESO to examine further the Rider C structure to minimize imbalances between market participants.

Commission findings

701. The Commission is satisfied with the AESO's explanation that changes to Rider C are not expected to change materially the number of customers who receive refunds or charges in annual deferral account reconciliations.

702. The Commission notes that while the ADC expressed the view that the design of Rider C may have been a contributing factor to substantial overcharges to some of its members who were subject to refunds by way of deferral accounts, the ADC did not request changes to the design of Rider C in this proceeding.

703. The Commission considers that the timing of comprehensive tariff updates, the need, timing and structure of annual tariff update applications, deferral account reconciliation

procedures and Rider C design are closely related, the Commission agrees with the AESO that it ought not to be prescriptive in respect of any of these specific matters.

704. The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.

8 Other matters

8.1 Effects of ongoing proceedings regarding ISO rules on transmission line losses

705. In the application, the AESO forecast transmission line losses of \$136.9 million for 2013 and \$123.7 million for 2014, this represents about eight per cent and seven per cent of the AESO's transmission revenue requirement for 2013 and 2014, respectively.⁴²⁴

8.1.1 Background

706. In its application, the AESO stated:

This comprehensive tariff application provides the forecast costs to be recovered through the AESO's rates, including costs related to transmission wires, ancillary services, transmission line losses, and the AESO's own administration (which includes other industry costs and general and administrative costs). The application also proposes changes to the rates and terms and conditions.⁴²⁵

707. On April 16, 2014, following the date that the AESO application closed, the Commission issued Decision 2014-110, which found:⁴²⁶

112. The review panel has considered carefully the evidence regarding how the 2005 Line Loss Rule operates and finds that it does not comply with Section 19(1)(a) and Section 19(2)(d) of the 2004 *Transmission Regulation* and Section 25(6)(b) of the 2003 *Electric Utilities Act*.

And

124. For all of the above reasons the review panel finds, pursuant to Section 25(6)(b) that the AESO's 2005 Line Loss Rule is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the 2003 *Electric Utilities Act* or the regulations.

⁴²⁴ Exhibit No. 26, page 9, Table 2-1.

⁴²⁵ Exhibit No. 26, paragraph 2.

⁴²⁶ Decision 2014-110, paragraphs 112 and 124.

708. On April 16, 2012, the Commission issued Decision [2012-104](#),⁴²⁷ in which the Commission found:

156. Finally, and most importantly, the Commission finds that the complaint regarding the line loss rule is valid for the period 2006 to 2008 when the rule complained about was in effect.

8.1.2 ATCO Power letter and supplemental process

709. On May 15, 2014, the Commission received a letter from ATCO Power regarding transmission line loss charges. ATCO Power stated that in the AESO's application, forecast transmission line losses of \$136.9 million for 2013 and \$123.7 million for 2014 represent about eight per cent and seven per cent of the AESO's transmission revenue requirement, respectively.

710. ATCO Power noted that the AESO's current line loss rule is the subject of two separate complaint proceedings before the Commission, and related issues in the context of Phase II of Proceeding No. 790.⁴²⁸ At the time ATCO Power's letter was received, the complaint proceedings were being held in abeyance. ATCO Power submitted that having regard to the findings in Decision 2014-110, that the 2005 line loss rule is "unduly preferential, arbitrary or unjustly discriminatory," the current line loss charges derived by the AESO based on the 2005 line loss rule cannot be just or reasonable and do not meet the statutory requirements set out in Section 121(2) of the *Electric Utilities Act*.

711. Additionally, ATCO Power stated that similar concerns exist in ongoing proceedings before the Commission with respect to the post-2008 line loss rule and that there can be no reasonable basis upon which to allow the AESO to charge rates that are based on a rule and a methodology that is "unduly preferential, arbitrary or unjustly discriminatory."

712. ATCO Power submitted that the rates the AESO proposed to charge in the application cannot meet the legislative requirements of Section 121(2) of the *Electric Utilities Act*, and should be disallowed on this basis. In the alternative, and without prejudice to the arguments that ATCO Power may make in other proceedings, ATCO Power requested that the Commission make a specific direction in this proceeding that line loss charges that are sought to be collected by the AESO in the application be charged on an interim refundable basis.

713. ATCO Power stated that this approach will ensure that any determinations that are made by the Commission regarding the line loss rule, and any resulting line loss charges, will be in accordance with the requirements of the *Electric Utilities Act* and applicable legislation and that market participants are not prejudiced by the collection of charges under an unjustly discriminatory tariff.

714. The Commission issued a letter on May 23, 2014 requesting brief supplemental argument submissions regarding the effect, if any, that Decision 2014-110 may have on the transmission line loss charges proposed in the AESO application. Supplemental argument submissions were due on June 6, 2014.

⁴²⁷ Decision 2012-104: Milner Power Inc., Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, Application No. 1606494, Proceeding No. 790, April 16, 2012.

⁴²⁸ Proceeding No. 790.

715. In its supplemental argument submission, ATCO Power explained further that in the context of Proceeding No. 790, certain parties have suggested that the Commission does not have the jurisdiction to change retroactively or order to be changed the AESO final tariffs under which the costs of transmission losses have been recovered since January 1, 2006. Having regard to these submissions that suggest that financial compensation would be addressed by the Commission through the AESO tariffs but that the Commission would have no jurisdiction to change retroactively the AESO's final tariff, ATCO Power requested that the Commission either disallow the portions of the AESO tariff that relate to the recovery of transmission losses or, at minimum, require that any line loss charges recovered under the AESO tariff be recovered on an interim basis. In this way, the issues underpinning the line loss charges can be considered and tested by the Commission.

716. Later in its submission, ATCO Power stated that in the circumstances, where the AESO's overall forecast of line loss costs would not change with a line loss rule and methodology that complied with applicable legislation, ATCO Power accepts that the AESO should be entitled to recover, on an interim refundable basis, provision for those line loss costs.

717. The AESO stated that the Commission's findings in Decision 2014-110 are limited to the 2006-2008 time period and that the extent to which the findings in Decision 2014-110 may apply to the AESO's current line loss rule has not yet been determined and is before the Commission in other proceedings. The AESO stated that if necessary, it did not object to the Commission approving transmission line losses on an interim refundable basis, but further stated that any direction of the Commission should be clear that only the line loss component of rates STS, DOS, XOS and IOS are interim refundable.

718. EEC submitted that currently, the Commission has not found that the post-2008 line loss rule violates the requirements of the governing regulatory framework and that it is simply not possible to perform an "all other things being equal" adjustment on loss charges and credits after the fact. EEC was opposed to interim refundable treatment of line loss charges.

719. TCE stated that Decision 2014-110 has no effect on the transmission line loss charges proposed in the AESO's GTA, and that it does not deal with, and explicitly does not invalidate, the line loss rule currently in effect. In Section 6 of Decision 2014-110, the Commission expressly ruled that the decision does not extend to "the AESO Line Loss Rule as it exists today" and to "the line loss rule post 2008." TCE submitted that it would not be appropriate to assume that the current line loss rule will be found by the Commission to be invalid, based solely upon Decision 2014-110.

720. TCE further explained that when generators offer in to the power pool, they do so based on a business strategy that includes the transmission line loss charges in effect at the time of the offer, if those line losses are subsequently changed, generators have no ability to go back in time and change their offer strategy to account for the change, it is too late. TCE argued that there is no basis on which to disallow the line loss charges in the AESO's current tariff and that it would not be appropriate for the Commission to approve line loss charges on an interim refundable basis and, therefore, ATCO Power's request should be denied.

721. Capital Power submitted that the validity of the ISO Rule 501.10 is the subject of complaint applications before the Commission in other proceedings and, therefore, should not be determined in this application.

722. TransAlta stated that no finding or direction has been issued by the Commission regarding line loss charges for the period since 2008. Further, TransAlta submitted that any interim refundable charges will require calculation pursuant to a new ISO rule that has yet to be developed and there are significant jurisdictional questions raised by this issue, including (without limitation) whether a new ISO rule can be applied retroactively and whether financial reimbursement that stems from such an ISO rule change can be awarded retroactively. Lastly, TransAlta also raised some concerns about intergenerational equity of interim refundable line loss charges.

723. TransAlta submitted that it did not believe that the AUC has the jurisdiction to set interim and refundable rates for line losses in the current circumstance.

724. Milner Power agreed with ATCO Power and stated that the AESO's presently applied for tariff, to the extent the tariff incorporates the AESO's loss factor rule, cannot be approved by the Commission.

Commission findings

725. Section 121(2) of the *Electric Utilities Act*, requires the Commission to consider, when approving a tariff application, whether the tariff is just and reasonable and not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the *Electric Utilities Act* or any other enactment or any law.

726. Pursuant to Section 30(4) of the *Electric Utilities*, the AESO may "recover the costs of transmission line losses" by including those costs in the AESO tariff. Alternatively, these costs could be recovered outside of the tariff through the establishment of an ISO fee.

727. In this application, the AESO has included the line loss costs as part of its 2013 tariff update and 2014 tariff. Although the line loss costs are an included element in the AESO tariff, determination of the line losses is accomplished through the application of an ISO Rule. The requirement for the AESO to make rules to recover transmission system losses, as well as additional direction in the recovery of those losses, are found in sections 31, 32, 33, 34 and 36 of the *Transmission Regulation*.

728. The AESO's current line loss rule, calculated on the basis of loss factors determined in accordance with Section 501.10 of the ISO Rules, *Transmission Loss Factor Methodology and Requirements*, is the subject of separate complaint proceedings⁴²⁹ made by each of ATCO Power and Milner Power Inc., and related issues in the context of Stage 2 of Proceeding No. 790.⁴³⁰ These complaints, in respect of the current line loss rule and the determination of related issues, remain outstanding and have not been determined by the Commission.

729. In the event that, following the hearing of the complaints respecting the current line loss rule, there is a determination made by the Commission that the ISO rule is technically deficient, does not support the fair, efficient and openly competitive operation of the market or is not in the public interest,⁴³¹ the Commission could order that the rule be changed or disallowed. In that

⁴²⁹ Milner Power Inc. and ATCO Power Canada Ltd. filed separate complaints with the Commission, Application No. 1608563 and Application No. 1608709 respectively regarding the AESO's line loss rule post 2008.

⁴³⁰ Proceeding No. 790, Milner Power Inc. complaint against the ISO line loss rule.

⁴³¹ See Section 25(1)(b) of the *Electric Utilities Act*.

event, the line loss component of the 2013 tariff update and 2014 tariff, may not meet the requirements of Section 121(2) of the *Electric Utilities Act*.

730. Consequently, in consideration of the outstanding complaint process regarding the ISO line loss rule, the Commission will approve the 2013 and 2014 line loss component on an interim basis pursuant to Section 124(2) of the *Electric Utilities Act* and Section 8(5)(c) of the *Alberta Utilities Commission Act*.

731. The AESO explained that in the proposed 2014 Tariff, the forecast costs of transmission line losses are collected only under Rates DOS, *Demand Opportunity Service*; XOS, *Export Opportunity Service*; STS, *Supply Transmission Service*; and IOS, *Import Opportunity Service*. Therefore, it is only the line loss charge component of rates STS, DOS, XOS and IOS that are made interim.

732. Following a determination of the line loss complaint proceedings referenced above, the AESO may bring forward an application to address the outcomes of those proceedings as they relate to the line loss component of its 2013 and 2014 tariff.

8.2 Responses to directions

733. In Section 8 of the application, the AESO provided Table 8-1: Directions Responded to in the 2014 ISO Tariff. In that table, the AESO responded to directions from decisions 2010-606,⁴³² 2011-049,⁴³³ 2011-275,⁴³⁴ 2012-362,⁴³⁵ and 2013-034⁴³⁶ and noted where the responses to those directions occurred within the application.

734. Other than the submissions filed by AML and Access/Devon regarding the customer contribution policy and proposed investment formula, which is discussed in other sections of this decision, no parties provided any comments regarding the responses to directions from prior decisions.

Commission findings

735. Upon review of Section 8 of the application and the record of this proceeding, the Commission is satisfied that the AESO has provided responses to directions from prior decisions that are directly related to the proposed tariff. Where parties disagreed with the responses, those matters are discussed in other sections of this decision.

8.3 Proforma construction commitment agreement

736. As noted in paragraph 10 of this decision, the AESO included its proposed *proforma* construction commitment agreement as Appendix B to its proposed 2014 ISO tariff.

⁴³² Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Application No. 1605961, Proceeding ID. 530, December 22, 2010.

⁴³³ Decision 2011-049: Alberta Electric System Operator, 2009 Deferral Account Reconciliation, Application No. 1606095, Proceeding ID No. 89, February 10, 2011.

⁴³⁴ Decision 2011-275: Alberta Electric System Operator, Compliance filing pursuant to Decision 2010-606 and 2011 Tariff Update, Application No. 1607003, Proceeding ID. 1074, June 24, 2011.

⁴³⁵ Decision 2012-362: Alberta Electric System Operator, 2012 Construction Contribution Policy, Application No. 1607193, Proceeding ID No. 1162, December 28, 2012.

⁴³⁶ Decision 2013-034: Alberta Electric System Operator, 2010-2011 Deferral Account Reconciliation, Application No. 1608444, Proceeding ID No. 1878, February 7, 2013.

737. When a market participant requests system access service from the AESO and the provision of the system access service requires the construction of new transmission facilities, the AESO tariff requires the market participant to provide security to the TFO to fund the financial obligation of the transmission facilities in an amount determined by the operation of the AESO tariff.

738. The *proforma* construction commitment agreement is the contract between the TFO and the market participant for the construction of new transmission facilities and the commitment by the market participant in relation to the expenditure of capital for such construction.

739. Although a draft *proforma* construction commitment agreement had been included in the application, the AESO continued to discuss and review the language of the agreement with the TFOs, AltaLink and ATCO Electric. As it became clear that a final form of agreement could not be reached during this proceeding, the Commission directed the AESO to withdraw the *proforma* construction commitment agreement and related documents from consideration in this proceeding. The Commission commented that “[w]hile the Commission recognizes that discussion and review of the construction agreement among the AESO, AltaLink and ATCO Electric may be an effective method to refine the agreement, the Commission is concerned that other parties registered in this proceeding, who may be affected either directly or indirectly by any changes to the construction agreement, and whose involvement in the consultation process is not readily apparent to the Commission, may require more testing of the construction agreement than the AESO currently anticipates.” The Commission directed the AESO to submit for testing and approval its amended *proforma* construction commitment agreement once it had completed its consultation.

Commission findings

740. This direction remains outstanding. As it has roughly been nine months since the Commission directed the AESO to submit for testing and approval its amended *proforma* construction commitment agreement, the Commission directs the AESO to file its application for approval of its *proforma* construction commitment agreement by December 31, 2014.

9 Supply opportunity service (Module 2)

9.1 Background

741. In its evidence, TransCanada proposed a new supply opportunity service rate (Rate SOS) to be included in the AESO’s 2014 tariff and submitted that it “has proposed Rate SOS to address transmission constraints, and the resulting congestion costs, arising from the connection of new generators to the transmission system or increases to existing generation capacity.”⁴³⁷ TransCanada stated that the inclusion of Rate SOS is intended “to provide a transitional service to new generating units in Constrained Areas until adequate transmission is available.”⁴³⁸

742. TransCanada submitted that during periods of constraint, generating units under Rate SOS would be curtailed before Rate STS customers.⁴³⁹ The offer of Rate SOS would be

⁴³⁷ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 1.

⁴³⁸ Exhibit No. 154.02, TransCanada evidence, paragraph 13.

⁴³⁹ Exhibit No. 154.02, TransCanada evidence, paragraph 15.

contingent on the AESO finding that a transmission reinforcement is required in order to provide unconstrained market access under normal operating conditions or to meet applicable reliability and planning criteria upon the proposed connection of a new entrant.⁴⁴⁰ TransCanada submitted that the purpose of Rate SOS is to allow new generating units to connect to the AIES with the understanding that they would be curtailed prior to dispatching or constraining down incumbent generating units that are subject to Rate STS. This Rate SOS would continue until adequate transmission capacity has been added in the constrained area, at which point the Rate SOS customer would qualify for system access under Rate STS.⁴⁴¹ TransCanada added that new generators that do not cause or exacerbate constraints under normal operating conditions would continue to be offered Rate STS, as would new generators that might cause or exacerbate constraints only under abnormal operating conditions.⁴⁴²

743. ATCO Power, TransAlta, and ENMAX made submissions that were generally supportive of TransCanada's Rate SOS proposal. The AESO, BluEarth, Capital Power, the CCA, and the UCA made submissions that were, for the most part, opposed to TransCanada's Rate SOS proposal.

744. As noted previously in the decision, the Rate SOS Proposal was the subject of a separate module and parties provided substantial argument regarding the merits of the proposal. The Commission has created the following subsections to assist the reader in the presentation of the various arguments raised by both the proponents and the detractors of the Rate SOS proposal.

9.2 Existing "connect and compete" practice

745. The AESO submitted that its current approach, which it has used consistently to connect new entrants since the beginning of 2012,⁴⁴³ is to treat new entrants and incumbents equally to the extent possible through the existing "connect and compete" approach.⁴⁴⁴ Under this approach, a new entrant will be connected and receive the same priority of service as an incumbent, subject to the potential for a remedial action scheme and the requirement that the AESO alleviate any resulting constraints that may occur under normal operating conditions.

746. The "connect and compete" approach is described in the *AESO Practices for System Access Service* information document, which specifies that there are three conditions that must be met before a market participant will be connected in a constrained area: (1) the AESO must publicly make available a plan to remove the constraint (should it arise under normal conditions or result from a single contingency event that requires a remedial action scheme (RAS)); (2) the existing market participants that are affected by a constraint have the ability to utilize energy market offers and bids that can be used to determine access; and (3) a determination from the AESO that it will be able to operate the system in a safe, reliable and practical manner after the connection of a new market participant.

747. The AESO's current "connect and compete" practice is applied when the preceding three conditions are met. If the AESO determines that constraints are anticipated to arise under normal operating conditions, the AESO connects market participants and "facilitates competition for

⁴⁴⁰ Exhibit No. 154.02, TransCanada evidence, paragraph 19.

⁴⁴¹ Exhibit No. 154.02, TransCanada evidence, paragraph 16.

⁴⁴² Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 7.

⁴⁴³ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 21.

⁴⁴⁴ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 3.

system access for all market participants.”⁴⁴⁵ In its *AESO Practices for System Access Service* information document, the AESO indicated that this practice allows the transmission system to be “used more efficiently and system access service is provided on a timelier basis when connections are advanced in this manner.”⁴⁴⁶

9.3 Does Rate SOS constitute a “reasonable opportunity” to exchange electric energy and ancillary services?

748. In accordance with its transmission responsibilities, the AESO has a duty to provide transmission system access pursuant to Section 29 of the *Electric Utilities Act* which states:

The Independent System Operator must provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so.

749. TransCanada stated that it understood Section 29 of the *Electric Utilities Act* to mean that the AESO cannot refuse to provide a market participant access to the transmission system – it must do so. However, it stated that the AESO has discretion as to the “manner” in which system access service is provided in that the system access service provided need only give market participants a reasonable opportunity to exchange electric energy and ancillary service, not an absolute right to do so. As such, the “reasonable opportunity” relates to the exchange of electric energy by market participants, not to the provision of system access service by the AESO.⁴⁴⁷

750. TransCanada submitted that “it is reasonable that the opportunity to exchange electric energy provided to an Entrant whose connection to the system causes such an interruption to the normal operation of the market, should differ from that of an existing generator” and argued that “[w]hile both are entitled to a reasonable opportunity to exchange electric energy, that opportunity is and should be different for each.”⁴⁴⁸ It stated that a reasonable opportunity does not mean an identical opportunity,⁴⁴⁹ and argued that the AESO’s approach in treating each generator equally to the extent possible overemphasizes the opportunity of new entrants at the expense of the existing generator’s opportunity.⁴⁵⁰

751. In support of TransCanada’s Rate SOS proposal, ATCO Power, TransAlta and ENMAX argued that the proposal met the statutory requirement to provide a “reasonable opportunity” to access the Alberta inter-connected transmission system.

752. ATCO Power submitted that providing different service priorities for system access service to customers would be aligned with the Alberta market framework as system access is not a “right” but, rather, something that all market participants wishing to exchange electric energy and ancillary services should have a reasonable opportunity to do so.⁴⁵¹ It argued that Rate SOS is similar to the existing RAS in which a proposed generator has the option to receive

⁴⁴⁵ *AESO Practices for System Access Service* information document, May 31, 2013. Also see Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 74.

⁴⁴⁶ *AESO Practices for System Access Service* information document, May 31, 2013. Also see Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module page 8.

⁴⁴⁷ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 17.

⁴⁴⁸ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 24.

⁴⁴⁹ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 24.

⁴⁵⁰ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 27.

⁴⁵¹ Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 3.

conditional access or wait until a time when a RAS might no longer be necessary. As Rate SOS will give a proposed generator the option to receive access that is recallable during times of constraints or to wait until transmission upgrades have eliminated the possibility of transmission constraints under normal operating conditions, there is nothing inconsistent with the provision of Rate SOS and the provision of a reasonable opportunity to access the Alberta inter-connected electric system where there may be insufficient transmission available.⁴⁵²

753. TransAlta submitted that the Rate SOS proposal allows for “reasonable access”⁴⁵³ and provides new entrants with an option to consider other connection points or to defer its generation until there is sufficient transmission capacity to accommodate the connection.⁴⁵⁴ In addition, Rate SOS would ensure that the entire financial effect of transmission constraints to incumbents and new entrants would be considered when choosing a connection point.⁴⁵⁵ It added that entrants who plan their new generation projects based on the AESO’s planned in-service dates for transmission reinforcement will not be subject to Rate SOS.⁴⁵⁶

754. ENMAX argued that a “reasonable opportunity” should strike a balance between existing and new generators in which new entrants are still allowed to connect (with full knowledge of transmission system conditions) before the infrastructure required to accommodate them fully has been constructed, and in which incumbents are not subjected to risks that they have no possibility of managing.⁴⁵⁷

755. The AESO expressed two main objections to the Rate SOS proposal. First, “is its infringement of the AESO’s reasonable opportunity obligation”...second, “is that the Rate SOS proposal is not fully developed.”⁴⁵⁸ With respect to its first main objection, the AESO disagreed with the views of TransCanada, ATCO Power, TransAlta and ENMAX in respect of its statutory requirement to provide market participants a “reasonable opportunity” to access the transmission system. The AESO stated that a “reasonable opportunity” should not discriminate between different supply market participants and in its view, Rate SOS and its inherent priority access for incumbents (or special access conditions for new entrants) does not provide new entrants with a reasonable opportunity to access the transmission system on non-discriminatory terms and should be rejected by the Commission.⁴⁵⁹

756. The AESO submitted that Rate SOS does not appear to be more consistent with the fair, efficient and openly competitive operation of the market than the current system access practice and it could be viewed as unjustly discriminatory against new entrants and giving undue preference to incumbents.⁴⁶⁰ In this regard, the time of entry into the generation market is not a valid basis upon which to distinguish between supply market participants and that doing so

⁴⁵² Exhibit No. 412.02, ATCO Power argument, Rate SOS module, paragraph 39.

⁴⁵³ Exhibit No. 337.01, TransAlta evidence, Rate SOS module, page 3.

⁴⁵⁴ Exhibit No. 337.01, TransAlta evidence, Rate SOS module, page 4.

⁴⁵⁵ Exhibit No. 337.01, TransAlta evidence, Rate SOS module, page 4.

⁴⁵⁶ Exhibit No. 337.01, TransAlta evidence, Rate SOS module, page 5.

⁴⁵⁷ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 36.

⁴⁵⁸ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 6.

⁴⁵⁹ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 71.

⁴⁶⁰ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 8.

would appear to have greater effects on new entrants particularly those with less locational flexibility, such as wind, hydro, and cogeneration tied to resource development.⁴⁶¹

757. The AESO also submitted that it would expect new entrants to make best efforts to avoid the constraints that these new entrants would be subject to under the AESO's connect-and-compete practice in order to receive the benefits that flow from their full available energy over all hours.⁴⁶²

758. The AESO submitted that Rate SOS would require a new entrant to take a lesser service than an incumbent, in an area subject to constraints under normal operating conditions, something that the AESO considers to be unjustly discriminatory,⁴⁶³ and "could have a chilling effect on Alberta generation investment."⁴⁶⁴ In addition, the AESO submitted that this unequal access is discriminatory as it will be accompanied by no reduction in associated charges as Section 47 of the *Transmission Regulation* requires that the costs of the transmission system be wholly charged to loads and exporters, with no transmission system costs to be charged to generators under any service option.⁴⁶⁵ The AESO submitted that because STS customers are not allocated fixed transmission system costs, there cannot be an appropriate discount between STS and SOS that could justify the different levels of service proposed. Further, the AESO argued that the Commission had already provided direction regarding service levels in Decision 2013-025 in which it determined, when considering Rate IOS, that available transfer capability over the interties is not allocated to the interties and importers based on priority for incumbents.⁴⁶⁶

759. Capital Power responded to TCE's and ATCO's arguments that entrants have options with respect to Rate SOS in that they will either accept the lesser access afforded under Rate SOS, delay the timing of their investment, or find another location for their investments, stating that "these are false choices that would be forced upon Entrants under Rate SOS and thereby create barriers to entry."⁴⁶⁷ Capital Power submitted that Rate SOS would be contrary to the purposes of the *Electric Utilities Act*; particularly Section 5(d) which provides that investments in generation of electricity are to be guided by market forces.⁴⁶⁸ It also agreed with the conclusion expressed in the AESO's rebuttal evidence "that giving Incumbents priority access to capacity that is constrained during normal operations would be inconsistent with the obligation to provide generation market participants with a reasonable opportunity to access the transmission system."⁴⁶⁹

760. Capital Power also disagreed with the suggestions by TCE and ATCO that Rate SOS may increase certainty for new investment and argued that it would create another layer of uncertainty

⁴⁶¹ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 8.

⁴⁶² Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 24.

⁴⁶³ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 51.

⁴⁶⁴ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 27.

⁴⁶⁵ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraphs 52-54.

⁴⁶⁶ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module paragraph 45.

⁴⁶⁷ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 13.

⁴⁶⁸ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 13.

⁴⁶⁹ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 14.

in the generation development process as entrants may not know until late in the planning stage if they would be subject to Rate STS or Rate SOS.⁴⁷⁰

9.4 Does Rate SOS amount to transmission rights?

761. In Decision 2009-042,⁴⁷¹ the Commission considered sections 17 and 29 of the *Electric Utilities Act* and determined that there are no explicit or implicit transmission rights and access to the transmission system, for all generators, is a reasonable opportunity and not a right. The Commission stated:

158. The Commission is not persuaded by NaturEner's submission that curtailing new entrants is discriminatory. The AESO stated that new entrants are subject to the results of system impact studies during the planning stage which may indicate the need for some mechanism, such as RAS, to ensure the safety and reliability of the AIES. The Commission has determined that there are no explicit or implicit transmission "rights" but that the obligation imposed on the AESO is to provide market participants with a reasonable opportunity to access the AIES. There is nothing inconsistent with the requirement of a RAS scheme and the provision of a reasonable opportunity to access the AIES where there may be insufficient transmission available.⁴⁷²

762. As well, in Decision 2013-025, the Commission again considered the issue of transmission rights. In that decision, the Commission was considering this issue in the context of access over the interties. The Commission stated:

170. While the Commission considers the nature of opportunity service is not at issue in this proceeding, the Commission finds the nature of opportunity service to be informative. Within the AESO tariff importers and exporters are charged for access to the transmission system based on the Rate ISO Import Opportunity Service and Rate XOS Export Opportunity Service, which are provided as an opportunity service only when sufficient capacity exists on the transmission system to accommodate the scheduled capacity. Simply put there are no transmission rights in Alberta, whether they are rights for physical facilities (for intertie developers) or for commercial traders (for importers and exporters). (Footnotes omitted)

763. Given the Commission's previous determinations regarding the absence of transmission rights in Alberta, parties addressed the issue of whether the proposed Rate SOS created transmission rights.

764. TransCanada argued that its proposal does not establish transmission rights. It asserted that transmission rights grant a right of access to capacity on a particular transmission path or grant a right of payment for the cost of congestion, which are not the same as a priority of service proposal such as Rate SOS.⁴⁷³

⁴⁷⁰ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 19.

⁴⁷¹ Decision 2009-042: Alberta Electric System Operator, Objections to ISO Rule 9.4, Transmission Constraints Management, Application Nos. 1568587, 1577949, 1577950, 1577951, 1577957, Proceeding ID. 41, April 9, 2009.

⁴⁷² Decision 2009-042, paragraph 158.

⁴⁷³ Exhibit No. 409.01, TransCanada argument, Rate SOS Module, paragraphs 31-34.

765. TransAlta similarly argued that Rate SOS does not create transmission rights because Rate SOS provides access priority that does not give incumbents any of the legal rights created by either physical or financial transmission rights.⁴⁷⁴

766. ATCO Power submitted that Rate SOS is not materially different from the current and previous tariff with regard to system access service priorities, mentioning different Rate DOS types in the existing tariff application.⁴⁷⁵

767. ENMAX argued that the Rate SOS proposal is not contrary to the Commission's determination that there are no explicit or implicit transmission rights in Alberta, and that the Rate SOS proposal is consistent with the existing regulatory framework.⁴⁷⁶

768. The AESO stated:

In its process letter dated February 21, 2014, the Commission indicated that it considers the issue of transmission rights to be settled, and reiterated its previous findings that there are no explicit or implicit transmission rights in the Alberta energy market. Instead, the obligation imposed on the AESO is to provide all market participants with a reasonable opportunity to access the transmission system and, as a result, the energy market, which the AESO will refer to as the "reasonable opportunity obligation". In this proceeding, there are two competing views of the reasonable opportunity obligation.⁴⁷⁷

769. The AESO submitted that sections 15(1) and 17 of the *Transmission Regulation* are engaged in the consideration of transmission rights and system access issues as Section 15(1) pertains to certain planning obligations for the AESO and Section 17 refers to management of constraints that may occur.⁴⁷⁸ The AESO indicated that:

[S]ubsection 15(1)(e) of the *Transmission Regulation* sets out certain obligations that the AESO must consider when planning the transmission system. It does not establish the requirements for system access service nor the rates or terms and conditions that are applicable to system access service. In particular, the AESO understands that its planning obligations would remain the same whether system access service was provided under Rate STS or under TCE's proposed Rate SOS. That obligation requires the AESO to plan the transmission system to accommodate all anticipated in-merit energy of generating units regardless of what system access service they receive.⁴⁷⁹

770. The AESO referenced Decision 2009-042 in support of its position that incumbent generators do not have preferential opportunities to access the AIES and Decision 2013-025 in support of its position that there are no explicit or implicit transmission rights, and that generators are only entitled to reasonable access to the AIES on a non-discriminatory basis.

771. BluEarth requested that TransCanada's proposal for the inclusion of Rate SOS in the AESO tariff be denied on the basis that it appears to be "an implicit transmission right to be

⁴⁷⁴ Exhibit No. 405.01, TransAlta argument, Rate SOS module, paragraph 5.

⁴⁷⁵ Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraphs 19-21.

⁴⁷⁶ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 2.

⁴⁷⁷ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 2.

⁴⁷⁸ Exhibit No. 407.02, AESO argument, Rate SOS module, paragraph 9.

⁴⁷⁹ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 59.

enjoyed by incumbents over new entrants”⁴⁸⁰ and is “clearly unduly preferential and unjustly discriminatory.”⁴⁸¹ In comparing the RAS to the Rate SOS proposal, BluEarth stated that it understood that RAS requirements, when needed, have been determined by the Commission to be permissible because of the AESO’s mandate to ensure the safe and reliable operation of the AIES, whereas, the “Rate SOS proposal appears to be grounded instead in an approach of providing incumbent generators with greater access to the AIES based upon when a generator connects to the system...”⁴⁸² It asserted that access to transmission availability based on timing of connection to the system amounted to *de facto* transmission rights prevailing in the Alberta context, regardless of whether it is effected as a tariff, a practice, a rule or an authoritative document.⁴⁸³ As Rate SOS is mandatory and results in one market participant having a reduced ability to access the power pool through diminished transmission access as compared to another party, the party not subject to Rate SOS “enjoys what amounts to in Alberta to be a transmission right.”⁴⁸⁴

772. Capital Power also argued that Rate SOS would establish “what in effect would be transmission rights” in favour of incumbents relative to entrants, thereby not providing entrants with a reasonable opportunity to access the AIES.⁴⁸⁵ It stated that Rate SOS amounts to priority access with no consideration of the dispatch merit order, and is “a transmission ‘right’ by another name.”⁴⁸⁶ Capital Power further argued that Rate SOS is contrary to previous Commission determinations regarding system access and transmission rights and referenced Decision 2009-042, Decision 2013-025 and Decision 2013-135.⁴⁸⁷ It asserted that in Decision 2013-025, the Commission rejected arguments that imports and exports should be treated differently for the purposes of providing system access service than other supply and demand transactions in the market. It also argued that the Commission rejected ATCO Power’s proposal for the establishment of transmission rights to deal with transmission constraints in AUC Decision 2013-135, a proposal which it asserted was similar to Rate SOS.⁴⁸⁸ Capital Power concluded by noting that the only special-access condition that the Commission has permitted has been the AESO’s use of RAS schemes for reliability purposes,⁴⁸⁹ and that Section 29 of the *Electric Utilities Act* requires that market participants wishing to exchange electric energy are to be provided a “reasonable opportunity to do so” and “on non-discriminatory terms.”⁴⁹⁰

9.5 Rate SOS and economic signaling

773. TransCanada argued that its Rate SOS proposal provided an opportunity to create certainty that would foster long-term investment in the Alberta market, help protect the fidelity of Alberta’s single market price for electricity and reduce transmission constraints and congestion costs. Conversely, it asserted that the AESO’s current practice contains “perverse

⁴⁸⁰ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 5.

⁴⁸¹ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 6.

⁴⁸² Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 5.

⁴⁸³ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 14.

⁴⁸⁴ Exhibit No. 421.02, BluEarth reply argument, Rate SOS module, paragraph 16.

⁴⁸⁵ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 4.

⁴⁸⁶ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 11.

⁴⁸⁷ Decision 2013-135: ATCO Power Ltd. and ENMAX Energy Corporation, Complaints by ATCO Power Ltd. and ENMAX Energy Corporation regarding ISO rule Section 302.1: Real Time Transmission Constraint Management, Application Nos. 1607872, 1608282 and 1608465, Proceeding ID No. 1790, April 5, 2013.

⁴⁸⁸ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 7.

⁴⁸⁹ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 8.

⁴⁹⁰ Exhibit No. 408.02, Capital Power argument, Rate SOS module, paragraph 21.

economic incentives” that will lead to increased frequency of transmission constraints, an increase in congestion costs, investment uncertainty and higher costs for consumers.⁴⁹¹

774. ATCO Power submitted that implementing Rate SOS would reflect times of constraint when the system is not capable of fully transmitting to the market the benefit that additional supply could otherwise provide, which it claimed would give proposed generation an incentive that is reflective of the value that it brings.⁴⁹²

775. TransAlta argued that Rate SOS would create efficiency incentives through the orderly development of the power system by encouraging generation developers to signal their plans in advance and develop in areas with existing transmission capacity.⁴⁹³ It also argued that Rate SOS would reduce overall uncertainty for both incumbents and new generators, as it would encourage new entrants to consider the full cost of all constrained generation instead of only the portion of congestion that the new generator bears under the current policy.⁴⁹⁴ Additionally, TransAlta asserted that the AESO’s current connect-and-compete approach has the effect of creating more congestion, which is contrary to the market design and the public interest.⁴⁹⁵

776. ENMAX argued that allocating bulk system costs directly to consumers results in generators not necessarily factoring in the costs of consequential bulk-system upgrades into their project economics, a muted economic signal for new generators regarding siting and no financial mechanism to protect access to the transmission system for existing generators.⁴⁹⁶ As such, it stated that, whatever can reasonably be done in the context of the existing framework, to send a locational signal, is both rational and in the public interest.⁴⁹⁷

777. The AESO acknowledged that the underlying concept and arguments in support of Rate SOS were not without merit and stated that the Rate SOS proposal “may result in certain desirable outcomes from a long-term efficiency perspective.”⁴⁹⁸ However, it was not convinced that these desirable outcomes were achievable under existing legislation in the manner proposed by TransCanada or other parties.

778. The CCA argued that there are existing tools to provide price signals on the location of new generation; therefore, Rate SOS is not required to provide locational price signals.⁴⁹⁹ The CCA also opposed Rate SOS because it did not consider the proposal to be required for the long-term economic efficiency of the generation market. To the contrary, the CCA argued that Rate SOS is anti-competitive and discouraged new entry into the generation market.⁵⁰⁰

9.6 Who causes transmission constraints?

779. TransCanada’s Rate SOS proposal was created with the underlying assumption that new generators cause transmission constraints on the system. Therefore, it asserted that there is a

⁴⁹¹ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 5.

⁴⁹² Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 47.

⁴⁹³ Exhibit No. 405.01, TransAlta argument, Rate SOS module, paragraphs 8-9.

⁴⁹⁴ Exhibit No. 405.01, TransAlta argument, Rate SOS module, paragraph 14.

⁴⁹⁵ Exhibit No. 420.01, TransAlta reply argument, Rate SOS module, paragraph 6.

⁴⁹⁶ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 29.

⁴⁹⁷ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 31.

⁴⁹⁸ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 8.

⁴⁹⁹ Exhibit No. 413.01, CCA argument, Rate SOS module, paragraph 8.

⁵⁰⁰ Exhibit No. 413.01, CCA argument, Rate SOS module, paragraph 10.

rational basis and justification for providing different priorities of service to different generators depending on whether their connections to the system cause constraints under normal operating conditions.⁵⁰¹

780. ATCO Power and ENMAX supported TransCanada's premise. Both considered that the new entrant was in a better position than an existing generator to be able to respond to the constraint effects that would result from the additional connection of the new generator to the transmission grid.

781. ATCO Power submitted that Rate SOS is in the public interest and supportive of a FEOC market as it can be viewed as an opportunity service rate to allow proposed generators to connect in circumstances where the transmission system cannot fully accommodate their additional generation.⁵⁰² ATCO Power added that the nature and location of existing generators cannot be reasonably altered in response to new investment proposals,⁵⁰³ whereas a new entrant located in a constrained area will have "had the ability to locate elsewhere, or to stage facility construction to optimize the time between the completion of the New Generator and the transmission system upgrades."⁵⁰⁴ ATCO Power argued that Rate SOS is an option for new generation to receive early access when firm access is not available due to the state of the transmission system.⁵⁰⁵ The current design of the market creates significant risk for generation projects. Generators would not want to proceed with their generation investment only to find that they cannot get reliable access to the market due to congestion. ATCO Power further submitted that this risk "reduces the attractiveness of the market to potential investors than would have otherwise been the case and as a result manifests itself in terms of higher prices."⁵⁰⁶

782. ENMAX argued that based on its interpretation of prior Commission and board decisions, it is acceptable in the regulation of public utilities for tariffs and rates to discriminate between users or customers so as long as a reasonable distinction between those entities (upon which the differential treatment can be justified) exists.⁵⁰⁷ ENMAX argued that new entrants can manage their risks through locational and timing choices whereas incumbent generators cannot and that this was an appropriate basis to make such a distinction.⁵⁰⁸ ENMAX further argued that regarding remedial action schemes, the Commission accepted the proposition advanced by the AESO that there was no fault with applying such a scheme based on vintage to ensure system safety and reliability. ENMAX also argued that congestion-related curtailments involving a thermal and wind unit would fall solely on the thermal generator regardless of its offer behaviour due to the reverse merit order mechanism present in the transmission constraint management rule that is used to manage transmission constraints in real time and the fact that wind does not presently offer into the market.⁵⁰⁹ As such, ENMAX argued that one party's reasonable opportunity to access the transmission system should not be interpreted so as to allow that party's unilateral action to erode or impede another party's ability to compete in the market.⁵¹⁰

⁵⁰¹ Exhibit No. 409.01, TransCanada argument, Rate SOS module, paragraph 48.

⁵⁰² Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 3.

⁵⁰³ Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 43.

⁵⁰⁴ Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 44.

⁵⁰⁵ Exhibit No. 419.02, ATCO Power reply argument, Rate SOS module, paragraph 19.

⁵⁰⁶ Exhibit No. 339.02, ATCO Power evidence, Rate SOS module, paragraph 52.

⁵⁰⁷ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 47.

⁵⁰⁸ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 48.

⁵⁰⁹ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraphs 54-55.

⁵¹⁰ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 57.

ENMAX furthered argued that allowing a wind generator to connect to the system when it will create congestion under normal operating conditions is not fair to incumbent generators and will not foster fair and open competition.⁵¹¹ ENMAX acknowledged that Rate SOS could be one of many barriers to entry that new entrants may face, but argued that this barrier is just for a specific location and not a barrier to market entry in general.⁵¹² On the other hand, an incumbent's transmission access could be "usurped"⁵¹³ by a new entrant, in some cases with no possibility of a rational competitive response, also constitutes a potential barrier to entry.

783. The AESO responded to the views of the Rate SOS proponents by arguing that new entrants and incumbents are not distinguishable on the basis of constraint causation, and that it was inappropriate to solely attribute constraints to either new entrants or incumbents.⁵¹⁴ The AESO explained that in Alberta, load pays the cost of transmission, incumbents have no claim on the value provided by the transmission access, and the legislation requires non-discriminatory system access for all market participants. "In this context it would be inappropriate to characterise New Entrants as causing constraints identified at the planning stage just as it would be inappropriate to suggest that Incumbents cause those constraints."⁵¹⁵ The AESO stated that since constraints occur as a result of all market participants and it is not possible to identify an individual market participant's contribution to a constraint or factors that may lead to its alleviation, it would be more appropriate to view both entrants and incumbents as equally responsible.

784. BluEarth rejected the Rate SOS proponent's assumption that new entrants could respond to potential congestion by moving their planned projects and argued that wind projects, such as Hand Hills, cannot realistically be moved and that not connecting them until additional transmission capacity is installed diminishes competition.⁵¹⁶ BluEarth further argued that price taking units such as Hand Hills may push price makers out of merit, and that this is in the public interest and "a positive factor in seeking to attain a competitive market"⁵¹⁷ that could result in lower pool prices.⁵¹⁸

9.7 Section 15(1)(e) of the Transmission Regulation

785. ENMAX argued that there are two incompatible access paradigms in the *Transmission Regulation* where generators are granted something of value (access to transmission) while absolving them of having to pay for it.⁵¹⁹ ENMAX also argued that the objective of the *Transmission Regulation* to attain a congestion free transmission system under normal operating conditions is extraordinarily difficult to achieve and has yet to be achieved more than a decade later.⁵²⁰ As such, it asserted that the default position should be that new entrants must either wait for any necessary transmission upgrades to be completed or accept a level of service that does

⁵¹¹ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 71.

⁵¹² Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 78.

⁵¹³ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 78.

⁵¹⁴ Exhibit No. 407.02, AESO argument, Rate SOS module, paragraph 27.

⁵¹⁵ Exhibit No. 407.02, AESO argument, Rate SOS module, paragraph 27.

⁵¹⁶ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 20.

⁵¹⁷ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 21.

⁵¹⁸ Exhibit No. 410.02, BluEarth argument, Rate SOS module, paragraph 24.

⁵¹⁹ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 12.

⁵²⁰ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 14.

not create congestion for incumbents.⁵²¹ ENMAX further argued that one cannot achieve a congestion-free system by intentionally connecting new generators in a manner that causes congestion.⁵²²

786. The AESO acknowledged that the essentially congestion-free transmission system contemplated by the *Transmission Regulation* has not yet been achieved, conceding that transmission development does not occur overnight, that it takes time and is “lumpy,” and that there are inevitable periods before transmission reinforcements are completed when constraints may occur.⁵²³

9.8 Completeness and implementation of the Rate SOS proposal

787. ATCO Power argued that a supply opportunity service rate should be implemented as soon as possible⁵²⁴ but acknowledged that while the concept of Rate SOS is broadly supported by TCE, TransAlta and ATCO Power, it is cognizant that these market participants have differing views regarding some of the details of a supply opportunity service.⁵²⁵ As a result, ATCO Power expressed its view that an AUC proceeding is not the appropriate forum to clarify the details of the supply opportunity service and argued that an AESO-led consultative process with market participants would be an efficient manner to finalize the details of Rate SOS.⁵²⁶

788. ENMAX argued that the Commission should find the Rate SOS proposal to be in the public interest and requested that the Commission direct the AESO to conduct a comprehensive stakeholder engagement on these issues, with a view to formulating and seeking Commission approval of the necessary rule(s).⁵²⁷

789. The AESO stated that although TransCanada suggests its proposed Rate SOS is complete and sufficient for immediate adoption into the AESO tariff, other parties have proposed amendments to Rate SOS, which suggests that Rate SOS may not be fully thought out.⁵²⁸ The AESO argued that Rate SOS is unclear, incomplete and impractical to implement.⁵²⁹ It expressed concern that “TCE’s Rate SOS proposal provides no provisions for defining when transmission constraints are considered to exist under normal operating conditions” and “appears to view the transmission system as a relatively static aggregation of parts that are subject to individual planning and development.”⁵³⁰ On the contrary, the AESO stated that “transmission planning is a more continuous and integrated process, with on-going optimization of the system reflecting local area and regional system evolution and growth over time.”⁵³¹ The AESO also asserted that TCE’s Rate SOS proposal does not appear to give consideration to other matters including circumstances that may benefit from discretionary treatment. Accordingly, the AESO submitted

⁵²¹ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 15.

⁵²² Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraph 19.

⁵²³ Exhibit No. 392.02, ATCO Power evidence, Rate SOS module, paragraph 5.

⁵²⁴ Exhibit No. 412.02, ATCO Power argument, Rate SOS module, paragraph 41.

⁵²⁵ Exhibit No. 412.02, ATCO Power argument, Rate SOS module, paragraph 42.

⁵²⁶ Exhibit No. 412.02, ATCO Power argument, Rate SOS module, paragraph 42.

⁵²⁷ Exhibit No. 411.01, ENMAX argument, Rate SOS module, paragraphs 106 and 107.

⁵²⁸ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 30.

⁵²⁹ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 30.

⁵³⁰ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 32.

⁵³¹ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 32.

that the Rate SOS proposal lacks sufficient clarity around the details and implications of Rate SOS, such that it cannot be implemented as proposed by TransCanada.⁵³²

Commission findings

790. Section 121 of the *Electric Utilities Act* requires the Commission, when considering whether to approve a tariff application, to ensure, *inter alia*, that the tariff is just and reasonable and that the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any enactment or law. Consequently, the Commission considers that in approving an AESO tariff, it must be satisfied that the AESO has complied with the legislative requirements imposed on it as directed by the *Electric Utilities Act* and the *Transmission Regulation*.

791. The legislative scheme contemplated by the provisions of the *Electric Utilities Act* and the *Transmission Regulation* reveals an underlying obligation on the AESO to create a transmission operating environment in which service is unfettered, recognizing that constraints can occur from time to time. For example, Section 15(1)(e) of the *Transmission Regulation* requires the AESO to plan a transmission system that accommodates 100 per cent of in-merit electric energy under normal operating conditions, and at least 95 per cent of in-merit electric energy during times of abnormal operating conditions, while Section 29 of the *Electric Utilities Act* requires the AESO to provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so.

792. As noted by all parties, the Commission has, in prior decisions, provided its determinations regarding Section 29 of the *Electric Utilities Act* first in the context of remedial action schemes and second, in its discussion of the allocation of available transfer capability over the interties. In Decision 2009-042, the Commission determined at paragraph 158 that “there are no explicit or implicit transmission “rights” but that the obligation imposed on the AESO is to provide market participants with a reasonable opportunity to access the AIES.” In Decision 2013-025 at paragraph 92, the Commission concluded that a “reasonable opportunity” pursuant to Section 29 of the *Electric Utilities Act* “constitutes non-discriminatory access and equal treatment of market participants, subject to any RAS requirements for maintaining safety and reliability of the AIES where there may be insufficient transmission available.”

793. Proponents of the Rate SOS proposal have presented arguments intended to demonstrate that the Rate SOS proposal does not contravene these findings of the Commission. The proponents assert that the Rate SOS proposal merely establishes priority to a path but falls short of establishing any legal right to transmission. Further, they argue that treating all participants equally, as the current AESO practice does, produces a discriminatory outcome in favour of new entrants. These proponents assert that because treating parties the same produces a discriminatory result, the requirement to provide a reasonable opportunity to access the transmission system as set out in Section 29 of the *Electric Utilities Act* does not necessitate providing the same opportunity to both new entrants and incumbent generators.

794. Detractors of the Rate SOS proposal argue that even if Rate SOS does not directly create a transmission right, the effect is the same. That is, by establishing differing access priorities,

⁵³² Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraphs 30-35.

Rate SOS indirectly creates transmission rights for incumbent generators, which they assert is discriminatory.

795. The proponents of Rate SOS argue that in the interests of fairness, incumbent generators, who they claim do not have the same flexibility or options to manage increased congestion in certain areas as new entrants, should have a first priority to access the transmission when there are constraints on the transmission system. The Rate SOS proposal presumes that it is fair to allocate superior access to incumbents on the basis that, as incumbent generators are already present and immobile, they should be given priority over new entrants that “cause” congestion. It is on this basis that the proponents’ claim that the current AESO practice is discriminatory, rests.

796. Conversely, the AESO has asserted that the timing of a generator’s entrance to the market should not be used to determine the assignment of the entitlement to transmission access and that new entrants and incumbents are not distinguishable on the basis of constraint causation. As such, it is inappropriate to attribute constraints to either new entrants or incumbents. The Commission agrees. It is just as legitimate, or illegitimate, to argue that, if incumbents had not located where they did within the transmission system, then entrants would not face a congested line upon entry, so it is incumbents, in locating where they did, that caused the congestion. Given the existing configuration of the AIES, congestion is caused by limited capacity and excess demand for this capacity that is made up of both entrants and incumbents. Allocating capacity to the AIES, whether congested or not, based solely on the timing of entry is unlikely to result in an efficient allocation of the available capacity.

797. Rate SOS proponents also argue that the current practice is discriminatory because entrants are able to respond to potential constraints by either relocating or delaying their projects, whereas incumbent generators cannot competitively respond. The Commission accepts the evidence of Capital Power, BluEarth and the AESO that the locational and timing flexibility attributed to them by proponents of the Rate SOS proposal is overstated. Many of the generation projects of new incumbents are wind, co-generation or hydro. As such, they cannot realistically be relocated. Further, the Commission accepts the evidence of Capital Power, BluEarth and the AESO that delaying their projects can diminish competition and that new entrants would, acting rationally, already be making choices to avoid constraints under the current AESO practice. For these reasons, the Commission rejects the premise of the Rate SOS proponents that new entrants have a greater ability to respond competitively to transmission constraints through re-locating or delaying their projects.

798. The Rate SOS proposal from TransCanada highlights a concern that there exists timing issues between the introduction of new generation and the “catch-up” necessary in planning to ensure a congestion-free transmission system in accordance with Section 15(1)(e) of the *Transmission Regulation*. The AESO also acknowledged that transmission development in Alberta takes time and that there are inevitable periods before transmission reinforcements are completed when constraints may occur.⁵³³

799. While the Commission understands the concerns of market participants who consider that the AESO is not developing transmission at a pace fast enough to satisfy their needs, the Commission is also sympathetic to the challenges that may be associated with certain aspects of

⁵³³ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 5.

the AESO's legislative responsibilities with respect to planning the transmission system as well as its assertions that:

Despite the AESO's efforts to plan and arrange for transmission infrastructure sufficiently robust to accommodate all in-merit energy when all transmission facilities are in service (i.e. under normal operating conditions), in reality, transmission development does not occur overnight. It takes time and it is lumpy. There are inevitably periods before transmission reinforcements are completed when constraints may occur. During these periods, the market cannot operate exactly as intended, but the AESO must nevertheless continue to provide all market participants with a reasonable opportunity to access the transmission system.⁵³⁴

800. Decision 2013-135 provides a direction to the AESO to make changes to the transmission constraint management rule which incorporates, among other things, having a single clearing price for energy in Alberta established by the intersection of unconstrained supply and demand curves, so as to prevent transmission congestion from setting or distorting the energy price. In July 2014, the AESO reported that it is making progress in respect of this rule revision.⁵³⁵

801. Under the existing "connect and compete" approach, all generators in an area that experiences transmission constraints under normal operating conditions will be subject to these transmission constraints. All other things being equal, a rational generator would likely choose to locate in an uncongested area than a congested one. A rational generator, should it choose to connect in a congested area, however, will have done so having taken into consideration the expected transmission congestion.

802. The Commission continues to find that, in Alberta, a "reasonable opportunity" requires equal treatment of market participants except in instances when the safety and/or reliability of the AIES is at risk. Under the legislative scheme, and as noted by the AESO, the costs of transmission are paid for by load, not generators. If differing levels of access by generators to the transmission system were contemplated under the legislation, it is reasonable to conclude that the legislation would have also enabled the differing access to be priced accordingly, as it is in other jurisdictions outside of Alberta that provide transmission access through an open access transmission tariff. Because the Rate SOS proposal, by design, does not treat market participants equally, the Commission does not view the Rate SOS proposal as providing a reasonable opportunity for all market participants to have access to the AIES.

803. The Commission rejects the Rate SOS proposal on the grounds that it results in implicit transmission rights, it does not provide all market participants with a reasonable opportunity to access the AIES, and timing is not a ground upon which to reasonably distinguish the new entrants or incumbents as the "causers" of transmission constraints.

804. As the Commission has not approved the Rate SOS proposal, the Commission has made no finding regarding whether the proposal as filed was sufficiently developed or, if not, what further process would be required to finalize the proposal.

⁵³⁴ Exhibit No. 392.02, AESO rebuttal evidence, Rate SOS module, paragraph 5.

⁵³⁵ The AESO published a "Revised TCM Rule Implementation Paper" on July 8, 2014 to their website here: http://www.aeso.ca/downloads/Revised_TCM_Rule_Implementation_Paper_070814.pdf

805. Last, as the Commission has not approved the Rate SOS proposal, the AESO's "connect and compete" approach continues to operate. As noted above, this approach is provided for in the *AESO Practices for System Access Service* information document and not in an ISO Rule. This decision does not address any potential issue regarding the means by which the AESO should be managing system access, whether through an ISO rule or AESO practice.⁵³⁶

⁵³⁶ In Decision [2013-382](#), Objections to Amendments to OPP 505 and ISO rules Section 302.5, the Commission stated at paragraph 47: "The Commission recognizes that other parties may be potentially affected by the issues raised concerning system access and the use of business practices. However, as this proceeding concerns objections to an ISO rule that is no longer in effect, it does not appear to be the suitable forum to address such concerns. The Commission will consider whether an industry wide consultation might be an appropriate vehicle to address such issues." See also Decision [2014-067](#), ATCO Power letter regarding Commission directions to the AESO in Decision 2013-135, at paragraph 49: "With respect to direction (4), ATCO Power requested that the AESO be required to file for approval with the Commission an authoritative document for transmission constraints at the planning phase. The Commission considers the issues of whether or not the System Access document contains authoritative material, and the differences between authoritative documents and information documents to be beyond the scope of this proceeding."

10 Order

806. It is hereby ordered that:

- (1) The AESO shall refile its 2014 ISO Tariff Application and 2013 ISO Tariff Update to reflect the findings, conclusions and directions in this decision on or before October 20, 2014.

Dated on August 21, 2014.

The Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Henry van Egteren
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
Alberta Electric System Operator (AESO) D. Holgate A. Pinjani I. Chow J. Martin S. Harland L. Kerr R. Sharma M. Jagbandhansingh
Access Pipeline Inc. (Access) J. Christian E. de Palezieux J. Dawson
Alberta Direct Connect Consumers Association (ADC) R. Secord C. Chekerda
ATCO Electric Ltd. (AE) L. Keough J. Grattan T. Martino S. Weiss A. Phillips S. Ambeault D. Hoshowski S. Yee L. Kizuk B. Yee L. Kerckhof B. Li
AltaLink Management Ltd. (AML) H. Williamson R. Block C. Hamm J. Smellie L. Jamieson Z. Lazic J. Yeo J. Piotto D. Madsen T. Kanasoot R. Senko N. Burns J. Wrigley

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Consumers' Coalition of Alberta (CCA) J. A. Wachowich A. P. Merani R. Retnanandan
Capital Power Corporation (Capital Power) D. E. Crowther S. Pillott G. Berry
Devon Canada Corporation (Devon) E. de Palezieux P. Speight
Dual Use Coalition (DUC) D. Hildebrand
ENMAX Corporation (EC) J. Schlauch D. Crippen T. Carle J. Dyson L. Weinstein
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EnerNOC, Inc. (EnerNOC) G. Poulos
Enbridge Pipelines (Athabasca) Inc. (Enbridge) E. de Palezieux K. Svidal
Enbridge Montana Alberta Tie Ltd. (MATL) R. Mcfarlane R. Stade

Name of organization (abbreviation) counsel or representative
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Industrial Power Consumers Association of Alberta (IPCAA) M. Forster R. Mikkelsen V. Bellissimo J. Cheng
The City of Lethbridge M. Turner O. Lenz D. Eaglesham
Milner Power Inc. M. S. Forster
Powerex Corp. (Powerex) L. L. Manning R. Hundal
The City of Red Deer M. Turner J. Jorgensen
Suncor Energy Marketing Inc. J. Maher
TransAlta Corporation (TransAlta) L. Berg G. Runnalls C. Codd
TransCanada Energy Ltd. (TCE) G. Fitch N. Berge V. Kostaskey S. Kley
TransCanada Keystone Pipeline GP Ltd. (Keystone) K. Thrasher N. Banner
Office of the Utilities Consumer Advocate (UCA) R. Daw H. Gnenz W. Taylor N. Jansen

The Alberta Utilities Commission

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B. Lyttle, Commission Member
H. van Egteren, Commission Member

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M. Ali (Commission counsel)
S. Karim
D. Ward
G. Andrews
J. Cameron
J. Halls
W. MacKenzie
K. Wyllie

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
Alberta Electric System Operator (AESO) D. A. Holgate A. Sears A. Klaiber-Langen	C. Terry J. Martin L. Kerr R. Sharma
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	R. Retnanandan
Dual Use Coalition (DUC) W. D. Hildebrand	D. Hildebrand
Alberta Direct Connect Consumers Association (ADC) and Industrial Power Consumers Association of Alberta (IPCAA) R. Secord	<u>ADC</u> M. Gorman C. Chekerda L. Olson <u>IPCAA</u> R. Mikkelsen
Office of the Utilities Consumer Advocate (UCA) T. D. Marriott M. Paul	R. Spragins J. Dalton T. Lusney
AltaLink Management Ltd. (AML) J. H. Smellie	
ATCO Power M. Buchinski T. Myers	C. Fuchshuber H. Klinkenborg D. Corbaci
ATCO Electric Ltd. (AE) K. Illsey	
TransCanada Energy (TCE) G. Fitch	
Powerex Corp. (Powerex) L. Manning	
Access Pipelines (Access) and Devon Canada Corporation (Devon) J. Christian	R. Cowburn E. de Palezieux
FortisAlberta Inc. (FAI or FortisAlberta) T. Dalgleish	M. Stroh
EnerNOC, Inc. (EnerNoc) G. Polous	J. Crawford

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Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The proposal of the DUC is denied. The AESO is directed to continue to exclude customer-owned projects from the database and POD cost calculations. Paragraph 208
2. The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database. Paragraph 260
3. In light of the considerations above, the AESO is directed to use the 1.5 MW low end data point to calculate the customer fixed charge in the POD charge in its DTS Rate in its compliance filing. Paragraph 285
4. The Commission finds the AESO's current practice to be helpful and the AESO is therefore directed to continue its current practice of providing its long-term transmission rate projections. Paragraph 422
5. Accordingly, the Commission directs the AESO to redraft applicable elements of its terms and conditions to reflect the Commission's findings that the AESO has discretion to move a previously discussed in-service target date for a system project to a later date when a change in key assumptions underpinning the target date have materially changed. For example, if projected dates for the filing or approval of a needs identification document or facility application has materially changed, the AESO has the discretion to shift the target in-service date as well. For greater certainty, if the AESO has been advised by the TFO that the originally discussed in-service target for a system-related project cannot be met without the TFO materially increasing its project budget, the Commission expects that the AESO should consider a change to the in-service date it sets as a possible solution. Paragraph 476
6. Conversely, the Commission considers that if a market participant requires a planned system project to be completed earlier than the in-service date and the AESO considers it to be reasonable in light of all relevant circumstances, this should be accommodated in the AESO tariff terms and conditions. However, in conjunction with this change, the AESO is directed to make it clear in its redraft of the relevant provisions that when a market participant elects to specify an in-service date earlier than the date the AESO had forecast for the system project that may be required as part of the requirements to connect the customer, including a subsequent revision of a target to a later date, the present discounted value of all the incremental costs and benefits as described in paragraph 474 above incurred in order to complete the system project by the requested date, rather than the initial target date will be deemed to be a participant-related cost for all purposes under the AESO's contribution policy. Paragraph 477
7. The AESO is directed to provide its redraft of the applicable provisions discussed above in its refiling application pursuant to this decision. Paragraph 479
8. Accordingly, the Commission denies the AESO's request to add subsection 3(3)(d) of Section 8 to its tariff terms and conditions. The AESO is directed to reflect this finding in its refiling. Paragraph 482

9. The Commission acknowledges the UCA's concern that the updated data workbook has not been extensively vetted and that the AESO's intention to utilize further updated data was not disclosed until a relatively late stage in the proceeding. With regard to the dataset used to prepare the response to ACCESS-AESO-001, parties had an opportunity to test this evidence during the oral hearing. The Commission understands that the updated data workbook has been prepared using this dataset. Although the AESO did not indicate that it would be using the updated workbook until the oral hearing, the Commission considers the preparation of the workbook is a fairly straightforward exercise. As there was an opportunity to test the dataset that formed the basis of the inputs into the workbook, the Commission is prepared to accept the results set out in the workbook for the purposes of this decision. However, the AESO is directed to identify any changes and adjust any results in its application of the updated dataset as part of its compliance filing. As there has been no opportunity to test any changes to the dataset since the oral hearing, the AESO is directed to remove any further changes to the dataset that it may have employed in the workbook that were not disclosed in the response to ACCESS-AESO-001. Paragraph 585
10. The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA. Paragraph 704
11. This direction remains outstanding. As it has roughly been nine months since the Commission directed the AESO to submit for testing and approval its amended *proforma* construction commitment agreement, the Commission directs the AESO to file its application for approval of its *proforma* construction commitment agreement by December 31, 2014. Paragraph 740