Alberta Electric System Operator

Compliance Filing Pursuant to Decision 2010-606 and 2011 Tariff Update

June 24, 2011
The Alberta Utilities Commission
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

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1 Introduction

1. On February 6, 2011, the Alberta Electric System Operator (AESO) filed an application (the application) with the Alberta Utilities Commission (the AUC or the Commission) pursuant to sections 30 and 119 of the Electric Utilities Act and to Decision 2010-606, and orders and directions made thereto.

2. Pursuant to the notice of application dated February 7, 2011, statements of intent to participate (SIPs) were received and accepted from the Dual Use Coalition (DUC), BC Hydro (BCH), TransCanada Keystone Pipeline Group Ltd. (TCKEY), ATCO Electric Ltd. (AE), the Industrial Power Consumers Association of Alberta (IPCAA), the Consumers’ Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), AltaLink Management Ltd. (AML), FortisAlberta Inc. (FAI) and the Alberta Direct Connect Consumers Association (ADC).

3. By letter dated March 7, 2011, the AESO filed certain amendments to the application (collectively, the refiled application) to reflect a proposed effective date of July 1, 2011. The refiled application requested the following relief:

   - Confirmation that it had satisfactorily responded to the Commission directions set out in Decision 2010-606.
   - Approval of the 2011 Independent System Operator (ISO) tariff provided as Appendix E to the application, to be effective July 1, 2011, including rates, riders, terms and conditions, and appendices.
   - Approval of the definitions provided as Appendix F to the application, to be effective July 1, 2011.
   - Approval of the 2010 construction contribution provisions in Section 8 and Section 9 of the ISO tariff provided as Appendix D of the application, to be effective from January 1, 2010 to June 30, 2011.
   - Such other relief as the Commission deems appropriate.

4. In accordance with the process and schedule for the proceeding set out in Commission correspondence dated March 30, 2011, argument was received from the AESO, AE, the UCA and the CCA.

5. By letter dated April 18, 2011, the Commission issued correspondence, which invited parties to comment on a specific aspect of Rate FTS under the AESO’s tariff in reply argument.

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6. Reply argument was received on or before April 26, 2011, from the AESO, BCH, the DUC, the ADC, the CCA and the UCA.

7. The Commission considers that the record for Proceeding ID No. 1074 closed on April 26, 2011.

8. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence, argument and reply argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission’s reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Compliance with Decision 2010-606 directions


10. In Decision 2010-606, the AESO was ordered to refile the 2010 ISO tariff to comply with the findings, conclusions and directions contained in Decision 2010-606.

11. The AESO provided a summary of Decision 2010-606 directions in Table 2-1 of the refiled application and provided a detailed discussion of its compliance with each direction in Section 2.3 of the refiled application.

12. In Appendix A to the refiled application, the AESO provided updated 2010 rate calculations reflecting Decision 2010-606 findings and directions.

13. In Appendix E to the refiled application, the AESO provided a comprehensive update to its tariff, including revised terms and conditions of service (T&Cs). In conjunction with the revised T&Cs, the AESO filed Appendix F, containing an updated list of definitions used in the refiled tariff.

2.1 Non-refiling directions

14. A number of directions set out in Decision 2010-606 did not require any action on the part of the AESO for the purposes of its refileling of the 2010 ISO tariff and instead pertained to requirements of an ongoing nature, or matters to be addressed in the AESO’s next major general tariff application (GTA). The Decision 2010-606 directions of this nature are summarized in Table 1 below:
### Table 1. Decision 2010-606 directions not related to 2010 GTA refiling

<table>
<thead>
<tr>
<th>Direction Number</th>
<th>Matter</th>
<th>Wording of direction</th>
</tr>
</thead>
</table>
| 3                | Transmission cost causation study update for next GTA                  | The Commission considers that the recommendation for an updated Transmission Cost Causation Study to be filed no later than July 1, 2011 is not reasonable. As discussed in section 11.1 of the Decision, the Commission has approved an AESO proposal to file comprehensive tariff applications every three years. In accordance with this approval, the Commission anticipates that the AESO’s next GTA will cover a test period commencing no earlier than 2014 and continuing in effect until 2016 or 2017. Given this anticipated timeframe, the Commission considers that the AESO’s next major cost causation study should reflect more meaningful TFO cost data that would be obtained as close as possible to the expected tariff term. The Commission has reviewed the process schedule prepared by the AESO as an undertaking to Commission counsel. The Commission finds that the process steps and timelines described therein can be undertaken in line with the AESO’s expected filing of its next GTA. 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.  

| 4                | Use of forecast system additions in future cost causation study        | The Commission does not consider it sufficient for the AESO to provide a model to permit interested parties to evaluate potential rate impacts under various assumptions, without incorporating forecast capital additions into the cost causation study. Accordingly, the AESO is directed to provide a forecast of anticipated transmission system additions and take this forecast into account in the AESO functionalization, classification, and rate design for each test year of the expected term of the AESO’s GTA which the Commission has directed be filed no later than March 31, 2013.  

| 5                | Use of long term transmission plan for next GTA                       | The Commission acknowledges the AESO’s observation that forecasts of major transmission system additions may be subject to significant uncertainty with respect to the actual cost and timing of transmission capital projects. However, in consideration of the major impact that assumptions may have on the reasonableness of the AESO’s ultimate rate design, the Commission expects that the AESO will make its best effort to ensure that information related to the forecast capital build is as accurate as possible at the date of filing of the AESO’s next GTA. To this end, the Commission directs the AESO to utilize the most recent AESO long term transmission plan at the time of the AESO’s next major GTA as the baseline for the “prospective component” of the transmission cost causation study. However, to the extent that the AESO is aware of any significant differences as to the expected composition, cost, or timing of transmission system additions described in the most recent long term transmission plan, the AESO is directed to make required adjustments within the transmission cost causation study filed with the GTA.  

| 12               | Future application for firm service export rate                       | The Commission accepts that the AESO’s rationale for not proposing a firm service export within the current application is reasonable. The Commission directs the AESO to continue to investigate firm export rates in consultation with stakeholders. In the event that transmission reinforcements pertinent to the export ATC are expected to be completed in advance of the GTA that the Commission expects to be filed on or before March 31, 2013, the AESO is directed to file a stand alone application for a proposed firm export rate on a timely basis.  

| 14               | Possible future changes to Rider C                                    | 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.  

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2 Decision 2010-606, paragraph 128.  
3 Decision 2010-606, paragraph 140.  
4 Decision 2010-606, paragraph 141.  
5 Decision 2010-606, paragraph 315.
23. Deadline for next comprehensive GTA

Consistent with the Commission’s prior findings in respect of Future Cost Causation Studies in Section 6.3 of this Decision, the Commission directs the AESO to file its next major tariff application no later than March 31, 2013.

Source: Prepared by Commission staff

Commission findings

15. The Commission acknowledges that the AESO has set out its intention to comply with directions from Decision 2010-606 which relate to future AESO applications, as summarized in Table 1 above. The Commission will assess the AESO’s compliance with these specific directions as required in future proceedings.

2.2 Refiling directions – non-contentious matters

16. The AESO filed several responses to directions set out in Decision 2010-606, which were of a fairly routine nature and were not identified as contentious matters by interested parties in argument or reply, or did not require the Commission to make additional comments in respect of the AESO’s response. The refiled application summarized the AESO’s responses to such directions in the manner set forth in Table 2 below:

Table 2. Routine and/or non-contentious GTA refiling directions

<table>
<thead>
<tr>
<th>Direction Number</th>
<th>Matter</th>
<th>Wording of direction</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Isolated generation cost classification</td>
<td>The Commission found in Section 6.1.2 of this Decision that the functionalization and classification of transmission wires costs should not incorporate the results of the Transmission O&amp;M Cost Study. In light of this finding, it would be inconsistent to utilize a portion of the Transmission O&amp;M Cost Study as the basis to change the classification of isolated generation costs to be on an energy basis. The AESO is directed to reflect this finding in its Refiling Application.⁶</td>
</tr>
<tr>
<td>2</td>
<td>Bulk system cost classification</td>
<td>The Commission has concerns, which are discussed in detail in Section 6.3.1 of this Decision, that the timetable proposed by the UCA for future cost studies is not logistically feasible. The Commission accordingly directs that the classification of bulk system costs remain unchanged for this tariff. The Commission anticipates this issue will be reviewed in the future.⁷</td>
</tr>
<tr>
<td>6</td>
<td>Treatment of isolated generation costs in primary service credit</td>
<td>In Section 6.1.4 of this Decision, the Commission directed the AESO to remove the effect of its proposed classification of isolated generation costs on an energy basis from its Rate DTS design. As this treatment of isolated generation costs has also been reflected in the AESO’s proposed PSC, the AESO is directed to adjust the PSC to remove the parallel treatment of isolated generation costs at the time of its Refiling Application.⁸</td>
</tr>
</tbody>
</table>

⁶ Decision 2010-606, paragraph 89.
⁷ Decision 2010-606, paragraph 104.
⁸ Decision 2010-606, paragraph 184.
| 7  | Revisions to subsection 5(3) of Rate FTS voltage control charge | The Commission directs the AESO to revise subsection 5(3) of the voltage control charge in Rate FTS to reflect the following wording in its Refiling Application:

   After completion of phase 1 of the northwest Alberta transmission development as approved in Approvals U2006-205, U2006-275, U2007-348, U2008-318 and others if applicable, the voltage control charge will also include the sum, over all hours in the settlement period in which Rainbow area load exceeds 145 MW and transmission must-run generation is required in the Rainbow area, of the cost associated with transmission must-run generation in the Rainbow area in an hour multiplied by the ratio in the hour of:

   (a) Fort Nelson load in excess of 38.5 MW; to
   (b) the sum of Fort Nelson load in excess of 38.5 MW and Alberta Rainbow area load (excluding Fort Nelson load) in excess of 106.5 MW. |

| 8  | Elimination of Rider H | The Commission finds that adopting the proposed change to how TMR costs are allocated under Rate FTS eliminates any future need for Rider H. The Commission directs the elimination of the interim refundable Fort Nelson Rider H and finds that there are no costs that need to be reviewed and reassessed for a final determination of costs under Rider H. |

| 9  | Continuation of existing local system charge in Rate FTS | The Commission directs the AESO to continue the existing local system charge and to revisit the charge either in its next GTA, or, if necessary, file a separate Rate FTS amendment application should BC Hydro’s requested service level, or the results of the coordinated planning effort between BC Hydro and the AESO, require a capital solution rather than a short-term TMR solution. |

| 11 | Rate FTS | The Commission directs that the AESO’s Refiling should reflect an updated Fort Nelson Demand Transmission Service, Rate FTS that incorporates the changes directed by the Commission. |

| 13 | Elimination of Rider I | In consideration of the above, the Commission makes no findings in respect of the merits of Rider I at this time. The AESO is directed to revise its proposed T&Cs to remove provisions related to Rider I in its Refiling. Rider I will be considered in association with the management fee in the upcoming 2011 Generic Cost of Capital proceeding (Proceeding ID. 833). |

| 16 | Final AESO oversight of GEIP | Nonetheless, given the concerns of parties and the practical implications that could arise, the Commission directs that the determination of facilities in excess of GEIP take a similar approach as the framework provided in Section 13 of the Transmission Regulation. Specifically, the Commission finds that the AESO can delegate the determination of facilities in excess of GEIP to TFOs; however, the AESO should review and approve any determination prepared under the delegation. Given the legislative framework and practical implications, the Commission considers that the AESO should retain final oversight over GEIP and the connection process including preparation of connection proposals by market participants, to ensure that there is non-discriminatory access to the system for all market participants. |

| 17 | Charge for facilities in excess of GEIP | The Commission directs the AESO to revise Section 8, subsection 4 of the T&Cs to clarify that a market participant must pay any participant-related costs of facilities which are deemed, in the opinion of the ISO, to be in excess of those required by GEIP. |

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9 Decision 2010-606, paragraph 255.
10 Decision 2010-606, paragraph 260.
11 Decision 2010-606, paragraph 264.
12 Decision 2010-606, paragraph 302.
13 Decision 2010-606, paragraph 390.
14 Decision 2010-606, paragraph 391.
21. PSS/AVR retrofit cost responsibility

Specifically, the Commission considers that the cost implications were not adequately addressed in this proceeding and therefore declines to approve the deletion of Article 4.4 from the T&Cs at this time. The Commission directs the AESO in its Refiling Application to explain how the AESO intends to address cost recovery for directions to regulated generators to install or upgrade PSS/AVR equipment in other authoritative documents. The Commission will make a further determination on the AESO’s proposal to eliminate Article 4.4 of the T&Cs following its consideration of the Refiling Application.\textsuperscript{15}

Commission findings

17. The Commission has reviewed the AESO’s responses to each of the Decision 2010-606 directions noted in Table 2 above. For each of these responses, the Commission is satisfied that the AESO has complied in full with the Commission’s directions.

2.3 Refiling directions – contentious matters

2.3.1 Direction 10 – restriction of termination charge to original AE line

18. In Direction 10 of Decision 2010-606, the Commission accepted a proposal of the AESO to incorporate a term within Rate FTS to protect against the potential risk for stranded costs in respect of the levelized cost of facilities serving Fort Nelson. The Commission also directed that the AESO include a similar provision for any levelized costs allocated to Fort Nelson for any future northwest Alberta transmission development.

19. The AESO confirmed that it had incorporated subsection 7(1)(a) from its originally proposed Rate FTS in subsection 7(1) of Rate FTS included in Appendix E of the refiled application.

20. In a letter dated March 28, 2010, BCH expressed concern with the AESO’s proposed Section 7(1) of Rate FTS. Specifically, BCH submitted that, while it understood that the intent of subsection 7(1) is to ensure the recovery of any stranded costs, the language should clarify that stranded costs would be calculated net of any residual benefit. BCH proposed the following rewording of subsection 7(1):

\begin{quote}
7(1) In addition to any obligations under section 9 of the ISO tariff, if BC Hydro terminates the system access service provided under this rate prior to the full payment of the levelized cost of the original ATCO Electric line providing service to Fort Nelson under subsection 3(3)(b) above; the ISO will determine the amount of the remaining unpaid balance of those costs net of any residual value, and BC Hydro will pay that amount to the owner of the transmission facilities. [added underlined words]
\end{quote}

21. In argument, the AESO indicated that it had accepted the changes to the wording of Section 7(1) of Rate FTS recommended by BCH in its March 28, 2011 letter.

22. In correspondence dated April 18, 2011, the Commission requested that the AESO explain, by way of letter, how it would expect to calculate “residual value” for the purposes of subsection 7(1) of Rate FTS, as proposed by BCH. All other parties were invited to make submissions on the AESO’s explanation in their reply submissions.

\textsuperscript{15} Decision 2010-606, paragraph 520.
23. In a letter dated April 18, 2011, the AESO responded to the Commission’s request as follows:

The AESO considers residual value to generally refer to the estimated present value of the net amount of costs and benefits expected to be attributable to a fixed asset over a future period after contract termination. The AESO expects that the determination of residual value in Rate FTS would consider:

- the remaining unpaid balance of the levelized cost of the original ATCO Electric line providing service to Fort Nelson (as provided in Information Response BCH.AESO-005 and Schedule BCH.AESO-005-A in the AESO’s 2005-2006 General Tariff Application proceeding);
- an allocation of the remaining unpaid balance to the AESO reflecting the extent to which the AESO planned to continue to use the original ATCO Electric line to provide system access service to Albertans or for any other purpose other than service to BC Hydro at Fort Nelson;
- any net salvage value (salvage proceeds less cost of removal) resulting from the line’s removal from service, if applicable; and
- any other costs, expenses, losses, benefits, or value arising from the future disposal or use of the line as determined to be reasonable and appropriate at the time.

...

24. The AESO submitted that it was not practical or reasonable to establish a methodology to calculate the residual value at this time. In the event that BCH terminated the system access service provided under Rate FTS, the AESO proposed that it would work with BCH to determine a reasonable residual value. The AESO submitted that Commission approval of the agreed-upon residual value would not be required, but noted that BCH could bring a complaint to the Commission if agreement could not be reached and it considered the amount determined by the AESO to be unreasonable.

25. The CCA agreed with the AESO that identifying a method for calculating residual value was not practical at this time. It recommended that the Commission identify and approve the parameters to be used in determining residual value. It suggested that the first three bullets put forward by the AESO are relevant parameters for determining residual value, but the fourth bullet dealing with “any other costs, expenses, losses, benefits, or value …” was too speculative and not in keeping with the principle of cost recovery and therefore should not be included as a consideration in the determination of residual value.

26. The CCA did not agree with the AESO’s contention that a negotiated settlement with BCH with respect to these costs would not require Commission approval. The CCA submitted that any negotiated settlement on residual value with BCH should be subject to AUC approval, similar to any other negotiated settlement with customers.

27. BCH indicated that it had reviewed the AESO’s response to the Commission request and it considered that the AESO had fairly stated the issues in relation to the determination of residual value.

Commission findings

28. The Commission sought further clarification on the concept of residual value and is satisfied with the response provided by the AESO. The Commission accepts the revised wording to subsection 7(1) of Rate FTS as proposed by BCH and supported by the AESO. Accordingly,
the Commission does not consider it is necessary to identify and approve the parameters to be used in determining residual value as recommended by the CCA. The Commission considers that any changes related to Rate FTS must be brought forward in a comprehensive tariff application, including the details of any negotiated settlement between the AESO and BCH.

2.3.2 Direction 15 – approval of amendments that materially change the tariff

29. Direction 15 from Decision 2010-606 pertained to the AESO’s obligation to apply for approval of future changes to its T&Cs in the event that a change has the effect of materially changing the tariff. The direction is worded as follows:

   Accordingly, the Commission directs the AESO to apply for approval of amendments which would materially change the tariff. Given this direction, Commission approves the AESO’s proposed reorganization of its T&Cs, subject to findings made in relation to specific provisions of the T&Cs below.16

30. In its discussion of its compliance with Direction 15 in the refiled application, the AESO noted its intention to apply for approval of “…any proposed substantial amendments or revisions to definitions or other provisions of the terms and conditions in the event such proposed changes could materially change the tariff.”17

31. Given this, the AESO noted that some definitions originally described within its 2010 GTA had been changed to reflect their use within ISO rules and Alberta reliability standards. Accordingly, the AESO stated that tariff definitions filed in Appendix F to the refiled application included minor changes to certain specified terms and that a new definition of “apparent power” had been adopted in Appendix F in substitution for the definition that had been set out within Rate DTS and Rate FTS of the 2010 ISO tariff application. The AESO noted that the revised definition of “apparent power” set out in Appendix F did not differ in meaning or intent from the definition removed from the Rate DTS and Rate FTS schedules.

32. The AESO noted that, in its written argument filed in the 2010 ISO tariff proceeding, it had proposed a definition of “good electric industry practice” (GEIP) that differed from the definition initially applied for in the 2010 ISO tariff. It stated that the change reflected comments received during consultations regarding definitions used in the ISO rules. However, the AESO also noted that the wording of the GEIP definition adopted in the ISO rules and in the Alberta reliability standards differed from the GEIP definition contained in the AESO’s argument filed in the 2010 ISO tariff proceeding.

33. The AESO submitted that the definition changes contained in the refiled application were minor in nature and did not impact the intent or interpretation of those definitions. The AESO indicated that the definition changes were included in the refiled application in order to ensure consistency of definitions throughout the AESO’s authoritative documents.

34. In addition to the definition changes set out in the refiled application, the AESO addressed questions about definitions used in the tariff that had arisen within information requests. In particular, the AESO noted that it was asked in information request AUC.AESO-00718 whether the definition of “Act” as used in the tariff also encompassed the

16 Decision 2010-606, paragraph 332.
17 Application, paragraph 52.
18 Exhibit 32.
regulations to the Electric Utilities Act. In consideration of this question, the AESO then proposed a further revision of its definition of “Act” as follows:

“Act” means the Electric Utilities Act and any regulations made under it. [added underlined text]19

35. The AESO also noted that, in information request AUC.AESO-008,20 it was asked to explain why the definition of GEIP should not take into account the methods, acts and standards of practice of neighbouring jurisdictions. The AESO noted that it had explained that the reference to “neighbouring jurisdictions” had been removed from the definition due to concerns regarding the potential need to monitor practices, methods and acts in other jurisdictions, as well as the implications of changes to practices, methods and acts in other jurisdictions if those changes resulted in inconsistencies with practices, methods and acts in Alberta. Given such concerns, the AESO submitted that its decision to remove the phrase “…and neighbouring jurisdictions” from the GEIP definition was reasonable.

36. In argument, the CCA submitted that, due to the interconnected nature of the system and the need to ensure that the judgment involved in applying GEIP is consistent with standards in other jurisdictions, the AESO should be directed to review the practices of neighbouring jurisdictions and harmonize its interpretation and practical application of good electric industry practice with those of other jurisdictions. In conjunction with this request, the CCA recommended that the phrase “…and neighbouring jurisdictions” not be removed from the GEIP definition.

37. In reply, the AESO submitted that its response to AUC.AESO-008(a),21 had noted that electric industry practices, methods, and acts are generally consistent among neighbouring jurisdictions. However, as also explained in the information request response, the AESO submitted that imposing a tariff obligation to maintain consistency with neighbouring jurisdictions would potentially require monitoring of practices, methods, and acts in other jurisdictions as well as assessments of changes to practices, methods, and acts in other jurisdictions if those changes resulted in inconsistencies with practices, methods, and acts in Alberta. On balance, the AESO submitted that any potential benefit arising from imposing an obligation for consistency with neighbouring jurisdictions would be outweighed by the requirement to monitor such consistency and to assess and respond to any inconsistencies that may be found.

**Commission findings**

38. The Commission notes that Direction 15 from Decision 2010-606 contains an ongoing requirement that the AESO apply for approval of material changes to its T&Cs, but did not explicitly require it to make changes to specific T&C provisions as part of its 2010 tariff refiling.

39. The Commission considers that, all things being equal, it is generally preferable that tariff T&Cs be as closely aligned as possible with other AESO authoritative documents. The Commission finds that the AESO’s proposal to update its T&Cs and file updated definitions as

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19 AESO argument, paragraph 12.
20 Exhibit 32.
21 Exhibit 32.
part of the refiled application was reasonable, and is consistent with Direction 15 from Decision 2010-606.

40. Having regard for the foregoing, the Commission is clarifying its expectation that the AESO will apply reasonable judgment in deciding whether or not an application to amend its tariff T&Cs is necessary in view of revisions to other AESO authoritative documents that may occur from time to time.

41. In respect of specific definition changes proposed in the refiled application, the Commission agrees with the AESO’s proposal to add the words “and any regulations made under it” to its definition of the Electric Utilities Act.

42. With respect to the CCA’s request that the AESO should be required to restore the references to neighbouring jurisdictions within the GEIP definition, the Commission has been given no reason to be concerned that the AESO will not monitor practices, methods and acts of neighbouring jurisdictions in the normal course of its operations. The Commission notes that the AESO indicated that electric industry practices, methods and acts are generally consistent among neighbouring jurisdictions. The Commission understands that, at any given time, practices, methods and acts accepted as GEIP within Alberta may differ from practices, methods and acts considered as GEIP in neighbouring jurisdictions. However, the Commission considers that it has not been demonstrated why it is necessary or beneficial to impose a specific obligation on the AESO to maintain consistency with other jurisdictions. Therefore, the Commission accepts the AESO’s revised wording of “good electric industry practice” as set out in the application.

2.3.3 Direction 18 – incremental O&M costs for facilities in excess of GEIP

43. Direction 18 of Decision 2010-606 reads as follows:

For these reasons, the Commission directs the AESO to eliminate the proposed Prepaid O&M charge in its T&Cs. The AESO is directed to add to its T&Cs a provision that will charge customers requesting optional facilities deemed to be in excess of GEIP the full incremental maintenance cost, incremental operations cost, and overheads associated with the operation and maintenance of those facilities. The charge should be customer specific and recovered as it is currently, as a construction contribution. It is anticipated that the customer making the request for optional facilities deemed to be in excess of GEIP will be required to estimate the incremental operations and maintenance costs and that the estimate must be agreed to by the AESO. The testimony of the AESO and other parties suggests that this will only be required in exceptional cases.\(^22\)

44. The AESO noted that, in Appendix E of the refiled application, it had revised subsection 9 of Section 8 of the T&Cs to indicate that:

- A market participant must pay, as part of the construction contribution, an operations and maintenance charge added to the cost of facilities which are deemed to be in excess of those required by good electric industry practice.
- The charge will be estimated by the market participant and agreed to by the AESO.
- The charge will include the full incremental maintenance cost, incremental operations cost, and overheads associated with the operations and maintenance of the facilities which are deemed to be in excess of those required by good electric industry practice.

\(^{22}\) Decision 2010-606, paragraph 486.
45. AUC.AESO-006 asked whether additional clarity could be gained by stating the market participant must work with the transmission facility owner (TFO) to estimate the operations and maintenance charge. The AESO responded that, given the requirement for the AESO to agree to the charge, this would ensure consistency in the estimates. Furthermore, the AESO would have the flexibility to review an estimated charge with the applicable TFO for reasonableness. Therefore, the AESO submitted that imposing a formal requirement for the market participant to work in conjunction with the TFO to estimate the O&M charge was not necessary. No other parties commented on this issue in argument or reply.

Commission findings

46. The Commission considers that the AESO’s revisions to subsection 9 of Section 8, as reproduced above (from Appendix E), comply with Direction 18. The Commission is satisfied with the AESO’s proposal that it will review any estimated O&M charges for reasonableness and consult with the TFO as necessary.

2.3.4 Direction 19 – notice waivers for energy efficiency projects

47. Direction 19 of Decision 2010-606 pertains to amendments to the AESO T&Cs proposed by the ADC in evidence filed in the 2010 ISO tariff proceeding. Specifically, during the 2010 ISO tariff proceeding, the ADC proposed amendments to the T&Cs that would:

- Permit demand ratchet and contract capacity to be waived or reduced for energy reduction or efficiency projects to the extent that they reduce energy consumption.
- Waive the five-year notice period for energy efficiency projects for DTS load that has local interconnection and POD facilities that have no unrecovered investment.
- Require the AESO to provide a five-year projection of its DTS tariff.24

48. In Decision 2010-606, the Commission found that notwithstanding that payment in lieu of a five-year notice is intended to reflect the share of fixed system costs incurred to accommodate the contract capacity of a market participant over a five-year planning horizon and to mitigate the risk of stranded costs, it may nevertheless be desirable to augment incentives for market participants to pursue energy reduction initiatives. These may be desirable in circumstances where it is clear that there is no risk of stranded investment and where there may be other benefits such as capital deferral or reductions in transmission must-run (TMR) or isolated generation costs.

49. The AESO was directed as follows:

Consequently, the Commission wishes to better understand the impact that the ADC’s proposal may have on the AESO and on other market participants. Therefore the Commission directs the AESO to provide a report to the Commission on this proposal at the time of its Refiling which will indicate specifically:

(a) the number of market participants that would reasonably be expected to take advantage of the notice relief sought by the ADC;
(b) the revenue impact if all market participants identified in part (a) were to exercise this option and reduce their DTS demand; and

23 Exhibit 32.
24 Decision 2010-606, paragraph 493.
(c) an assessment of whether it is feasible to apply incentives in specific regions and at a specific time in order to realize benefits such as capital deferral, or reductions in TMR or isolated generation fuel costs.  

50. Decision 2010-606 further noted that the Commission intended to make a further determination on the ADC’s proposal after receiving the above noted information.

51. Considering assumptions set out in the refiled application, and a further assumption that notice relief would not be made available to market participants that had requested contract capacity increases in the 10 years prior to the consideration of the energy reduction initiative, the AESO estimated that 24 market participants might be eligible for and take advantage of notice relief for the purposes of implementing energy reduction initiatives.

52. The AESO further estimated that market participant pursuit of notice relief in conjunction with energy reduction projects would cause a one-time revenue reduction in the range of $2 million to $4 million.

53. Further to part (c) of Direction 19, the AESO submitted that because subsection 5(6)(b) of Section 9 of the T&Cs already provides for the waiver of payments in lieu of notice where transmission system benefits arise from contract capacity reductions, there was no need to consider additional transmission system benefits arising from notice relief associated with energy reduction initiatives.

54. In argument, the AESO noted that its response to UCA.AEOS-001 indicated that the present value of the total customer savings from energy reduction initiatives ranged from $170 million to $260 million, based on the same assumptions that resulted in the forecast $2 million to $4 million revenue reduction arising from notice relief. Given this, the AESO submitted that the notice provisions in the current tariff would not be a real and material barrier to the implementation of energy reduction initiatives, since commodity savings are usually significantly larger than the impact of the tariff’s notice provisions.

55. The AESO submitted that information request CCA.AEOS-001 highlighted administrative concerns associated with granting notice relief for energy reduction, including the possibility that “free riders” would benefit from notice relief without specifically pursuing energy reduction initiatives. In addition, the AESO noted that, while the absence of contract increases over the last 10 years can be used to reasonably indicate the absence of stranded investment, assessing contract increases over a 10-year period may not address all possible circumstances that could result in stranded investment.

56. Considering the above, the AESO stated that it remained of the view that the waiver provisions already in the tariff appropriately recognize circumstances where a reduction or termination of capacity aids system planning. It submitted that the notice provisions included in subsection 5 of Section 9 of the ISO tariff should be approved as refiled, without further provision for notice relief.

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26 Exhibit 33.
27 Exhibit 31.
57. In its argument, the CCA stated that while it supported initiatives designed to promote societal benefits such as greenhouse gas reductions, it was concerned that the AESO’s proposed wording was not specific enough to confine the waiver of notice to energy efficiency and/or demand response programs. The CCA submitted that waiver notice should only be allowed if a reduction in demand results from a substantial energy efficiency initiative resulting in a permanent demand reduction or in support of dynamic demand response initiatives that would result in demand reductions in response to system conditions.

58. The CCA submitted that the AESO should be directed to propose wording that would confine the notice waiver to energy efficiency projects and customer demand response programs where the load may be controlled or dispatched by the AESO. The CCA submitted that the AESO should also propose appropriate definitions for energy efficiency and demand response programs that would qualify for waiver of notice.

59. The UCA submitted that no changes should be made to notice provisions related to energy reduction initiatives for several reasons, including that:

- Subsection 5(6)(b) of Section 9 of the refiled tariff already provides for the waiver of payments in lieu of notice where transmission system benefits arise from reductions of contract capacity.
- AESO calculations demonstrate that the small incremental savings that would arise from notice relief would have no impact on a customer’s decision to pursue an energy efficiency project.
- It is highly unlikely that the net book value of the relevant local facilities would ever be zero, so it is highly unlikely that there would be no stranded investment.

60. Consistent with findings in Decision 2005-09628 and 2007-106,29 the UCA submitted that the two-year 90 per cent ratchet provides a reasonable balance between customer flexibility and revenue stability and the five-year notice provision provides the appropriate economic discipline to enable the AESO to plan the system effectively. As such, the UCA submitted that changes to the current DTS ratchet and notice provisions are not warranted.

61. In reply, the AESO submitted that, if the notice provisions are not a barrier to energy efficiency projects, there would be no “societal benefit of greenhouse gas reductions” from the waiver of the notice provisions, as suggested by CCA. The AESO noted that subsection 5(6)(b) of the refiled tariff provides that determination of transmission system benefits is specific to individual circumstances and, as a result, is evaluated on a case-by-case basis. As such, the AESO submitted that if transmission system benefits arise, the waiver of notice should not be restricted to energy efficiency and demand response initiatives, as was suggested by the CCA.

62. The CCA responded to the submission of the AESO that the notice provisions included in subsection 5 of Section 9 of the ISO tariff should be approved as refiled, without further provision of notice relief. The CCA submitted that rather than rejecting the entire notice relief for energy efficiency project proposals, the AESO should be directed to come forward with a

practical way of facilitating energy efficiency and dynamic demand response project initiatives (through notice relief or otherwise) on the part of customers.

63. In reply, the UCA submitted that the CCA may have misinterpreted the AESO’s response to UCA.AESO-001 when it commented that significant customer savings in the absence of notice relief can be misleading because these are not savings resulting from dynamic demand response. In particular, the UCA submitted that the total savings of $170 million to $260 million shown in the response to UCA.AESO-001 represent savings that would accrue to 24 randomly chosen customers who implement energy reduction initiatives, and are not savings to all customers. As such, the UCA submitted these customers would receive incremental savings of between $2 million to $4 million above and beyond the savings of $170 million to $260 million that would accrue to these same 24 customers in the absence of any notice relief.

64. In reply, the ADC noted that it had accepted the AESO’s response to Direction 19, since the AESO’s response had addressed key concerns insofar as:

- The qualifying conditions would concentrate participation in notice waiver relief to a small number of market participants.
- The AESO’s administrative effort would not be onerous.
- The outcome would be fair to consumers – both those granted relief and the remaining rate base.

65. The ADC further noted that it was satisfied that the AESO’s proposed language to alter the T&Cs represented a workable solution. However, the ADC noted that the AESO had presented a contrary perspective during the course of the current proceeding with which the ADC disagreed.

66. The ADC submitted that the notion that the notice waiver provisions do not represent a barrier to the economics of a project should be rejected. The ADC noted that it had provided testimony during the 2010 ISO tariff proceeding that project economics vary and are unique to each project, and that foregoing payments in lieu of notice removes an unnecessary penalty to customers striving to be more efficient. In addition, the ADC submitted that it is unfair to require the payment of unnecessary penalties on potential participants who would not leave the system with any stranded investment.

67. The ADC submitted that the AESO’s evidence, as set out in the refiled application, indicates a low risk of stranded investment if a market participant has not increased contract capacity in the 10 years prior to the energy reduction initiative. The ADC submitted that the AESO had expressed a contradictory position in argument, by suggesting that assessing contract capacity increases over only a 10-year period may not address all stranded investment risk in light of the 40-year life of many transmission facilities. While noting that the AESO’s use of 10 years may be practical in light of the fact that longer term records may not exist, the ADC submitted that this concern could be addressed through the adoption of a hybrid approach whereby qualifying participants would have to demonstrate that they have taken service for 20 years and have not had any capacity increases during the prior 10-year period.

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30 Exhibit 33.
31 Exhibit 33.
68. Finally, the ADC submitted that, while the AESO suggests in argument that notice relief would likely create administrative challenges in assessing energy efficiency projects, concern over administrative challenges in evaluating proposals should not be a barrier. In particular, the ADC submitted that, with additional language suggested by the ADC, the proposed wording of subsection 5(6) of Section 9 of the T&Cs described at paragraph 93 of the refiled application would satisfy the ADC’s request for the waving of notice provisions.

**Commission findings**

69. The Commission has considered the arguments by the UCA, the ADC, the CCA and the AESO regarding notice waivers for energy efficiency projects. The evidence of the AESO suggests that a limited number of market participants would be expected to take advantage of this change in the notice provisions and that the one-time revenue impact appears to be relatively small in comparison to the overall AESO revenue requirement. Consequently, the Commission is persuaded that granting additional discretion to the AESO to waive normal notice requirements may be beneficial in certain circumstances. The Commission, therefore, generally accepts that the proposed changes to subsection 5(6) of Section 9 of the T&Cs as described at paragraph 93 of refiled application are reasonable. However, the Commission considers that the notice waiver provisions would be improved by the inclusion of ADC’s proposal, that qualifying participants must demonstrate that they have taken service from the Alberta grid for a minimum of 20 years, thereby providing additional assurances that there are no stranded investments. As such, the Commission directs the AESO to refile subsection 5(6) of Section 9 of the T&Cs to read as follows:

(6) If the ISO considers that circumstances warrant, the ISO may waive or reduce the requirement for payment in lieu of notice where:

(a) contract capacity is transferred to a system access service of the same market participant at a nearby transmission substation;

(b) transmission system benefits arise from the reduction or termination of contract capacity, which benefits may include relief of regional transmission constraints, removal of capacity limitations which would restrict system access service to other market participants or avoidance of future upgrades to the transmission system; or

(c) the reduction of contract capacity results from an energy or demand reduction initiative of the market participant who has taken service for at least 20 years who:

   (i) provides to the ISO a clear, thorough and convincing case, with supporting facts, that demonstrates the energy or demand reduction resulting from the initiative and

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32 At page 4 of its reply, the ADC proposes: (1) inclusion of language providing for the waiver of the 24-month ratchet for qualifying projects, and (2) a provision stipulating that qualifying participants must demonstrate that they have taken service from the Alberta grid for a minimum of 20 years.

33 Note: The underlining shown here denotes the additional language added to the version of subsection 5(6) of Section 9 of the tariff described at paragraph 93 of the refiled application but should not be underlined when the AESO refiles the tariff.
(ii) during the ten (10) years prior to the reduction in contract capacity becoming effective, has not increased contract capacity at the point of delivery at which the reduction in contract capacity will occur.

70. The Commission recognizes that each energy efficiency project will be unique and reflect specific economic circumstances. The Commission considers that it is at the discretion of the AESO to exercise the provision of notice waivers for energy efficiency projects. As such, the Commission expects that, in its consideration of such requests, the AESO will ensure that the waiver is necessary in order for the energy efficiency project to move forward and that there are no stranded costs that would be associated with the energy efficiency project.

71. With respect to the concern of the CCA regarding the potential for this provision to be used by “free-riders,” (that is market participants who reduce their demand or ratchet, but not as a result of any energy efficiency projects), the Commission considers that the risk of “free-riders” should be small so long as the AESO is diligent in investigating requests for notice waivers to ensure that the notice waiver is required to pursue a proposed energy efficiency project, and to ensure that the exit of the market participant giving notice does not give rise to incremental stranded costs that would otherwise be recovered by applying the primary notice provisions of the tariff. However, the Commission directs the AESO to file a report in its next GTA indicating the number of market participants that requested the waiver provided for in the revised subsection 5(6) of Section 9 and the reduction in tariff revenue arising from the approval of any such requests.

72. The AESO is further directed at the time of its next GTA to discuss any changes that should be made to notice provisions in light of its experience with the additional discretion to grant waivers approved in this decision.

2.3.5 Directive 20 – staged load and contract capacity increases

73. Direction 20 from Decision 2010-606 pertains to the calculation of maximum local investment for market participants that “stage” contract capacity increases over time. Direction 20 reads as follows:

The Commission directs the AESO to amend its proposed T&Cs to ensure that the intention of Article 9.7(a)(i) of the AESO’s current T&Cs is restored. The AESO should provide its proposed amendment and any associated rationale at the time of its Refiling Application.34

74. In its discussion of its compliance with Direction 20 the AESO noted that Article 9.7(a)(i) of its approved T&Cs reads as follows:

9.7 Staged Load & Contract Capacity Increases
(a) Where material increases or decreases in Contract Capacity are contemplated at a POC and contracted for in the original System Access Service Agreement then:
(i) Local investment for projects with expected material increases or decreases in contract load will be determined at the start of the project by taking the present value of the local investment in the incremental load for the remaining contract term ….

34 Decision 2010-606, paragraph 512.
75. The AESO indicated that it had revised subsection 8(6) of Section 8 of its T&Cs to comply with Direction 20. The AESO submitted that insofar as:

- part (a) of its revised subsection 8(6) references investment in incremental contract capacity; and
- part (b) of revised subsection 8(6) determines the present value of such investment

the AESO’s revisions to Subsection 8(6) meet the requirement of Direction 20 to restore the effect of Article 9.7(a)(i) of the T&Cs.

**Commission findings**

76. No parties addressed the AESO’s compliance with Direction 20 from Decision 2010-606 in argument or reply. The Commission has reviewed the AESO’s revised wording of subsection 8(6) of Section 8 of the T&Cs and considers that it has reasonably duplicated the effect of Article 9.7(a)(i) of the AESO’s currently approved T&Cs. Accordingly, the AESO’s compliance with Direction 20 of Decision 2010-606 is approved as filed.

2.3.6 **Direction 22 – system vs. customer cost classification**

77. Direction 22 of Decision 2010-606 reads as follows:

The AESO is directed to revise subsection 3(3) of section 8 of its proposed T&Cs to reflect the principles and criteria for classifying costs as system costs set out in Article 9.3(c) of the AESO’s current T&Cs in its Refiling Application.\(^{35}\)

78. In the application, the AESO noted that current Article 9.3(c) reads as follows:

9.3(c) System-related costs are those project costs associated with:

(i) Looped transmission facilities;

(ii) Radial transmission extensions if the transmission development plan (as that plan exists on the date the project is Commissioned) proposes that the Radial transmission extension becomes Looped within five years. The Customer will pay the cost of advancing that part of the project from the date established in the transmission development plan, calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.14; and

(iii) Where, in the sole opinion of the AESO, economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed, then the AESO will classify that portion of the project deemed to be in excess of the Customer’s needs as system-related costs. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer’s requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer’s requirements.

\(^{35}\) Decision 2010-606, paragraph 522.
The AESO noted that its rewrite of subsection 3(3) of Section 8 of the T&Cs had eliminated subsections 3(3)(b) through 3(3)(e) of its originally proposed version. After renumbering the remaining subsections of the original (subsections 3(3)(a), 3(3)(f), and 3(3)(g)), the revised subsection 3(3) of Section 8 reads as follows:

80. The AESO noted that subsection 3(3)(a) of Section 8 of the originally proposed T&Cs reflected the system-related classification of looped facilities contemplated in Article 9.3(c)(i) of the AESO’s currently approved T&Cs.

81. While subsection 3(3)(f) of the originally proposed T&Cs addressed the system-related classification of radial lines that are planned to be looped, the AESO noted that the renumbered subsection 3(3)(b) had been revised to include a condition that the lines must be planned to be looped in five years. The AESO also noted that the classification of the cost of advancing developments is addressed in subsection 3(2)(i) of Section 8 of the T&Cs.

82. Finally, the AESO noted that the renumbered subsection 3(3)(c) (formerly subsection 3(3)(g)) deals with the circumstances contemplated in the existing Article 9.3(c)(iii) where the AESO plans facilities larger than required to serve the market participant.

83. In argument, the AESO noted that AUC.AESO-004 questioned the rationale for designating costs as system-related if planned looping is set out “in a needs identification document filed with the Commission” or “as the ISO reasonably expects will be required in the future” in addition to the criteria that the connection is referenced in the most recent long term transmission development plan. The AESO submitted that sometimes it expects future looping projects to occur, but has not documented them in the most recent long term plan. Given this, the AESO submitted that it provides greater certainty to market participants to explicitly state that future looping projects not in the most recent long term plan will be classified as system costs, rather than relying on the AESO’s general prerogative to apply its discretion to system rather than participant cost classification.
Commission findings

84. The Commission has reviewed the AESO’s proposed revision to subsection 3(3) of Section 8 of the T&Cs and considers that the elimination of the originally proposed subsections 3(3)(b) through 3(3)(e) is consistent with the Commission’s direction.

85. The Commission notes that subsections 3(3)(b)(ii) and (iii) have added a further criterion beyond what is expressed in the current Article 9.3(c)(ii) whereby a radial extension is generally only afforded system treatment in the event that the radial extension would be part of a looped project contemplated in the most recent AESO long term plan. The Commission encourages the AESO to outline these staged developments in its long term plan, to the extent possible, so as to encourage full transparency respecting the assignment of system and customer costs.

86. The Commission has accepted the AESO’s explanation in AUC.AESO-004 that it may not always be possible to document anticipated looping projects in its long term plan. The Commission accordingly accepts that the AESO’s proposal to include parts (ii) and (iii) in its updated subsection 3(3)(b) is reasonable so long as the Commission can be assured that the looped project plans contemplated in subsections 3(3)(b)(ii) and (iii) were underway, but not documented in a long term plan, rather than being devised subsequent to the long term plan following the receipt of a market participant request to build radial connection to serve a new point of delivery (POD).

87. In the event that the AESO determines that a radial extension, that would otherwise be designated as a participant cost, should be categorized as a system cost because a needs identification document (NID) filed with the Commission includes a looping project, the Commission expects that the AESO will fully explain in the NID why the looping project was not included in the most recent long term system plan prepared by the AESO prior to the filing of the NID. Additionally, the Commission expects that the AESO will provide a complete discussion of why costs should be designated as customer or system costs. The Commission notes that any such approval by the Commission of the related facilities projects is not to be considered approval of the costs involved.

3 Other matters

3.1 2011 tariff update

88. In Section 3 of the refiled application, the AESO noted that paragraph 537 of Decision 2010-606 summarized the AESO’s proposed annual tariff update approach as follows:

In conjunction with its proposal for major updates, the AESO proposed to make annual tariff update filings involving the following three principal components:

- an annual revenue requirement update using the approach to the wires cost forecast as described in section 2.2 of the Application, plus forecasts for ancillary services costs, losses costs and administration costs approved by the AESO Board for the forecast year;

36 Exhibit 32.
• revised rate levels for each AESO rate calculated from the forecast revenue requirement and forecast billing determinants using rate calculations and rate design approved in the most recent comprehensive tariff application; and
• annual updates to investment amounts approved in the most recent comprehensive tariff reflecting an escalation factor based on the most recent Conference Board of Canada Alberta consumer price index (CPI).

89. The AESO noted that, while its 2010 ISO tariff application was prepared using the AESO’s forecast 2010 revenue requirement and forecast 2010 billing determinants, since that time, the AESO Board had approved costs for 2011 related to ancillary services, transmission line losses, and the AESO’s own administration. In addition, the AESO noted that TFO revenue requirement forecasts for 2011 had progressed to various stages of application and review.

90. Considering the above, and considering that the approved tariff will have a 2011 effective date, the AESO submitted that it was reasonable to incorporate its 2011 tariff update into its Decision 2010-606 compliance filing. The AESO noted that this proposal was presented to the Commission by letter dated January 14, 2011 and that, by letter dated January 26, 2011, the Commission approved the AESO’s proposal following a process that allowed interested parties to comment.

91. The AESO forecast that the cost of its 2011 revenue requirement would total $1,086.2 million, representing an increase of $43.5 million or 4.2 per cent over the $1,042.7 million total 2010 revenue requirement discussed in Section 2 of the application. The AESO also indicated that it had updated rate levels for each rate schedule to reflect the 2011 revenue requirement, using rate calculations prepared in compliance with Decision 2010-606, and updated billing determinants forecasts as described in Section 3.3 of the application.

92. The AESO noted that, using corresponding 2010 rate calculations set out in Appendix A as a template, it had prepared 2011 rate calculations provided in tables B5-1 through B5-13 of Appendix B of the application. In addition to its overall update of 2011 rates to reflect its 2011 revenue requirement forecast, in Section 3.2.1 of the application, the AESO provided additional comments on its 2011 updates to the following rates:

• Fort Nelson Demand Transmission Service Rate FTS.
• Primary Service Credit Rate PSC.
• Regulated Generating Unit Connection Costs in Rate STS.
• Wind Forecasting Service Cost Recovery Rider J.

93. In argument, the AESO noted that, while the SIP of the DUC had indicated that it did not support the application in light of the prospect that it would lead to rate increases of over 40 per cent for some load factor customers, the DUC had subsequently filed a letter in which it indicated that it was satisfied that the application should be approved as filed.
Commission findings

94. In Decision 2010-606, the Commission found that the AESO’s request in the 2010 ISO tariff to have major tariff updates at intervals and much simpler update applications on an annual basis effectively formalized the AESO’s existing practice as approved in Decision 2009-141. The Commission stated that it considered an annual revenue requirement and rate update may benefit customers by limiting potential misallocations that might occur if the AESO were to rely exclusively on Rider C to allocate periodic revenue/cost imbalances to its customers. The Commission considers that the AESO’s request to provide a 2011 tariff update, including the AESO Board approved costs for 2011 related to ancillary services, transmission line losses, and the AESO’s own administration and updated TFO revenue requirements for 2011 is consistent with this approach.

95. The Commission notes that the AESO used its established Budget Review Process to carry out consultation and to establish the 2011 forecast of $96.0 million for ancillary services, $121.0 million for transmission line losses, and $83.0 million for the AESO’s own administration costs. The Commission notes that the AESO determined the 2011 wires costs for transmission facility owners using the approach described in Section 2.2 of the AESO’s 2010 ISO tariff application for an updated TFO revenue requirement of $786.2 million. This results in a total forecast revenue requirement of $1,086.2 million, which represents an increase of $43.5 million (or 4.2 per cent) over the $1,042.7 million total 2010 revenue requirement. The Commission notes that the AESO 2011 Updated Business Plan and Budget Proposal, including these updated forecast costs for 2011, were approved by the AESO Board on December 7, 2010.

96. The Commission recognizes that the 2011 forecast revenue requirement has been approved by the AESO Board. As part of this process, the AESO must, in accordance with the Transmission Regulation, AR 86/2007, consult with those market participants that it considers are likely to be directly affected by the approval of its own administrative costs, costs for provision of ancillary services or the costs of transmission line losses. The Transmission Regulation requires the Commission to consider that the ISO’s own administrative costs, the ISO’s costs for the provision of ancillary services and the costs of transmission line losses that have been approved by the ISO members are prudent, unless an interested person satisfies the Commission that those costs or expenses are unreasonable.

97. The Commission notes that, while the SIP of the DUC had indicated that it did not support the refiled application in light of the prospect that it would lead to rate increases of over 40 per cent for some load factor customers, the DUC subsequently filed a letter in which it indicated that it was satisfied that the refiled application should be approved as filed.

98. No party objected to the forecast 2011 revenue requirement, nor did any party object to the inclusion of applied-for TFO tariff costs in the manner proposed by the AESO. As such, the Commission accepts the updated forecast 2011 revenue requirement and approves the proposed TFO tariff cost approach as filed.

38 Application, paragraph 134.
39 Application, paragraph 140.
40 Application, paragraph 134.
41 Subsections 3(1)(b), 46(1), 48(1), and 48(2).
99. In addition to its overall update of 2011 rates to reflect its 2011 revenue requirement forecast, in Section 3.2.1 of the refiled application, the AESO provided 2011 updates to the following rates:

- Fort Nelson Demand Transmission Service Rate FTS.
- Primary Service Credit Rate PSC.
- Regulated Generating Unit Connection Costs in Rate STS.
- Wind Forecasting Service Cost Recovery Rider J.

100. The Commission has reviewed the updated billing determinants forecasts, rate schedules and rate levels for each rate schedule to reflect the 2011 revenue requirement and considers that the rate schedules and calculations are consistent with Decision 2010-606.

3.2 Maximum investment levels

101. The AESO explained that the escalation factor for updating the maximum investment levels in Section 8 of the 2010 ISO tariff was calculated to be 0.981, a small decrease relative to the 2010 maximum investment levels. The detailed calculation was provided in appendix C of the 2010 ISO tariff application. A summary of the 2010 and 2011 Rate DTS maximum investment levels and the corresponding Rate PSC maximum investment levels was provided in Table 3-9 of the refiled application.

102. The AESO noted that the Commission had approved its proposal to apply annual updates to the maximum investment amounts approved in the most recent comprehensive ISO tariff application. The AESO proposed to apply an annual update reflecting a composite inflation index reflecting the most recent Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index (CPI) for Alberta for 2011.

103. The AESO indicated that it had updated the maximum investment levels to 2011 investment amounts according to the methodology approved in Decision 2010-606.

104. The UCA submitted that, while it did not object to the AESO’s proposed maximum investment levels for 2011, it was concerned that the AESO had not updated maximum investment levels for 2010 despite a reduction in the 2010 composite inflation index from a forecast of 1.941 in the 2010 ISO tariff to 1.866 as indicated in Appendix C to the refiled application.

105. The UCA submitted that, given that the Commission had accepted the use of the composite inflation index as a reasonable method to update maximum investment levels between rate applications, and given the Commission’s approval to implement new maximum investment levels for 2010 (retroactive to January 1, 2010), the maximum investment levels for 2010 should also be updated using the best information currently available.

106. The CCA submitted that, while it appreciated that uncertainty over investment levels could delay potential projects, the implementation of higher investment levels results in higher carrying costs for investments made in 2010 and the first half of 2011, which will necessarily be paid for by all other AESO customers.

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42 Decision 2010-606, paragraph 551.
107. The CCA submitted that investment levels are part of the AESO’s tariff and, therefore, the implementation date for all tariffs should be the same. Accordingly, the CCA submitted that the AESO should implement the proposed tariffs, including investment levels effective July 1, 2011. Alternatively, the CCA submitted that the AESO should calculate the additional carrying costs of the increase in investment levels in 2010 and the first half of 2011 and recover this amount from the specific customers who benefitted from the higher investment levels from January 1, 2010 to June 30, 2011.

108. The UCA submitted that contrary to the CCA’s view, the Commission has already determined that 2010 maximum investment levels should be effective from January 1, 2010. However, the UCA agreed with the CCA’s view that maximum investment levels are part of the tariff. As such, contrary to the view of the AESO, the UCA submitted that the Commission has not yet approved the final tariff which is the subject of the current proceeding. Furthermore, the UCA submitted that, while the Commission has approved the effective date of 2010 maximum investment levels, it has not yet approved the levels themselves. As such, any adjustment to the levels proposed by the AESO would not be retroactive and would not set a precedent for future retroactive adjustments.

109. In reply, the AESO rejected the CCA’s proposal to implement the tariff, including investment levels, effective July 1, 2011. The AESO submitted that the CCA’s view ignores the fact that Decision 2009-141 approved increased rates on October 1, 2009, without an accompanying increase in investment levels. The AESO submitted that the retroactive treatment of the maximum investment level to January 1, 2010, will actually improve the alignment between rates and investment levels during 2010. The AESO also submitted that the CCA’s proposal to update 2010 investment levels to reflect an updated 2010 composite inflation index is contrary to the approach approved in Decision 2010-606 to update investment levels between comprehensive tariff applications. The AESO argued that it considers that the 2010 maximum investment levels were approved as filed on a forecast basis, and there is neither direction nor compelling reasons to retroactively adjust them from the originally determined levels. It submitted that, in general, investment levels approved on a forecast basis should not be unexpectedly and retroactively adjusted to reflect later updates to the forecast inputs.43

110. With respect to carrying costs, the AESO pointed out that, because increased investment levels have not yet been applied, there will be no increased investment made during the first half of 2010 or the first half of 2011. With no increased investment being made, there are no carrying costs to be calculated or recovered from market participants and, therefore, no basis for the CCA’s proposal that the AESO calculate the additional carrying cost and recover the cost from specific customers who benefitted from the higher investment levels.

Commission findings

111. The Commission considers that the maximum investment levels for 2011 were updated in accordance with the methodology proposed by the AESO and approved by the Commission in Decision 2010-606.44 The Commission considers that the recommendations of the CCA and the UCA are not consistent with the approved methodology for making annual updates to maximum investment levels in conjunction with annual tariff updates,45 nor are they consistent with the

43 Exhibit 43, paragraph 44, page 8.
44 Decision 2010-606, paragraph 549.
45 Decision 2010-606, paragraph 551.
Commission’s finding in Decision 2010-606 that the construction contribution provisions contained in sections 8 and 9 of the tariff should take effect on January 1, 2010.\footnote{Decision 2010-606, paragraph 492.} For this reason, the Commission does not accept the recommendations by the UCA and the CCA to adjust the effective dates or to update the 2010 maximum investment levels to reflect updated data for the 2010 composite inflation index.

112. The Commission approves the 2010 maximum investment levels to be effective January 1, 2010 to June 30, 2011. The Commission approves the 2011 maximum investment levels to be effective July 1, 2011.

### 3.3 Financial obligations for connection projects

113. In Decision 2010-606, in respect of provisions related to financial obligations for connection projects, the Commission stated:

> However, the fact that one of the TFOs suggests that the AESO’s proposal has not been sufficiently vetted in its current form, raises a concern for the Commission. The Commission approves the revisions proposed, but expects the AESO and TFOs to work together to further identify and work to mitigate, or simplify, any potential administrative burden imposed on the TFOs.\footnote{Decision 2010-606, paragraph 403.}

114. In a filing dated March 7, 2011, the AESO noted that, in light of this finding, it had reviewed administrative matters related to the connection process. From this review, the AESO determined that the primary remaining concerns related to the estimation of amounts to be paid to cover project costs incurred by the TFO’s in accordance with subsection 2(6) of Section 5 of the T&Cs.

115. The AESO noted that, while it had discussed the administration of the monthly schedule of financial obligations with both TFOs and market participants, it had not yet been able to satisfactorily address concerns expressed by TFOs about the potential administrative burden that would be placed upon them. In particular, the AESO noted that as the schedule approach has not yet been implemented, it is unclear what additional administrative burden might be imposed, what types of projects the administrative burden might relate to, or how the administrative burden would compare to costs incurred by market participants if financial obligations were to be determined on a less-frequent basis.

116. The AESO submitted that, while it would continue to discuss this matter with stakeholders, it was not submitting any amendments to Section 5 of the T&Cs at this time. However, in the event that further discussions were to result in changes that would mitigate administrative burdens, the AESO indicated that it expected to request Commission approval for revisions to the tariff.

117. In argument, AE noted that subsection 2(6) of Section 5 of the AESO’s refiled T&Cs\footnote{In AE’s argument, this is referred to as “Section 5, part (6) of the Compliance Filing”.} sets out that the customer’s financial obligation will increase monthly by amounts equal to the estimated costs incurred by the TFO. However, AE submitted that, for connection projects under $10 million, the rigorous monthly process contemplated in subsection 2(6) would be too administratively onerous for TFOs.
118. AE submitted that it would not be reasonable to treat all projects under the same monthly process schedule. It stated that it had participated in the AESO facilitated consultations following the issuance of Decision 2010-606, but that no consensus had been reached on how to best deal with differences in the size of connection projects. However, to reduce the administrative burden imposed on TFOs for smaller projects, AE proposed that the AESO define a threshold cost level which would separate large projects from smaller projects. It proposed that large projects be dealt with in accordance with subsection 2(6) of Section 5 of the T&Cs, and that the goal for smaller projects should be to minimize the administrative burden of collecting the customer’s financial obligation over the life of the project. AE proposed that the threshold level should be set at $10 million to distinguish between large and smaller projects for this purpose.

119. In addition to the above, AE also sought to clarify that “incurred costs” for the purposes of subsection 2(6) of Section 5 of the AESO’s T&Cs includes all costs that the TFO is obligated to incur in the construction of a connection project. In this regard, AE submitted that for the purposes of subsection 2(6) of Section 5 of the AESO’s T&Cs, “incurred costs” that can be recovered from the connecting customer should include:

- Upfront engineering work required for the project.
- Commitment costs including project related requisitions not yet created as a purchase order.
- Project related purchase orders not yet billed or received.

120. AE submitted that its interpretation of incurred costs for the purpose of Section 5 of the T&Cs was consistent with the AESO’s response to AE.AESO-001(b)49, in which the AESO stated that:

... the AESO considers that "all costs the owner of the transmission facility incurs or is required to incur in ... construction of the project” would include all construction and material costs reasonably and prudently incurred that were associated with ordering goods and services from vendors. (underlining added by AE)

121. In reply, the AESO noted that subsections 3(6) and 4(4) of Section 5 of the refiled tariff allow a market participant to provide security and construction contribution amounts greater than the monthly schedule of financial obligations described in subsection 2. Given this, and given that market participants and AE are likely both interested in avoiding the administrative burden of frequent payments and reporting for small projects, the AESO submitted that it should be possible to expect that parties could agree on a less frequent schedule without the need for imposing a prescriptive approach within the tariff.

122. The AESO submitted that AE’s proposal to set a $10 million threshold for the application of the financial obligations set out in subsection 2(6) of Section 5 was too high. It noted the response to FAI.AESO-001 (b-c),50 which indicated that that the average cost of a connection project was $8.6 million. As such, the AESO submitted that AE’s proposed threshold would be expected to exclude more than half of the connection projects analyzed by the AESO.

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49 Exhibit 27.
50 Exhibit 29.
123. With respect to the request of AE for clarification that all commitment costs incurred by TFOs are recoverable as incurred costs, the AESO submitted that there is no need for further clarification of those costs in the tariff for two reasons. Firstly, subsection 5(1)(b) of Section 5 of the refiled ISO tariff continues to use the terms “cancellation costs” and “penalties” as they are used in Article 6.4(a) of the AESO’s currently-approved tariff. In addition, subsection 5(1)(a) provides that “all costs the owner of the transmission facility incurs or is required to incur in … construction of the project” includes all construction and material costs reasonably and prudently incurred that were associated with ordering goods and services from vendors.

124. The DUC indicated that it was strongly opposed to AE’s request in argument that monthly reporting of costs for projects under $10 million not be required. The DUC noted that during consultations held before the 2010 ISO tariff was filed, direct connect customers had expressed grave concerns with the lack of cost reporting by TFOs and a propensity for significant cost overruns.

125. The DUC submitted that customers who spend millions of dollars on capital contributions need as much notice as possible to make financial arrangements to cover cost overruns. Given this fact and that AE had not provided evidence to support its position that monthly reporting would be too burdensome, the DUC submitted that AE’s request to alter monthly cost reporting processes should be dismissed.

**Commission findings**

126. In Decision 2010-606, the Commission approved the AESO’s proposed revisions to subsection 2(6) of Section 5 of the T&Cs. However, it also noted that it expected the AESO and the TFOs to work together to further identify and work to mitigate, or simplify, any potential administrative burden imposed on the TFOs. The Commission acknowledges the AESO’s commitment to continue to discuss this matter with stakeholders, but as the administration of the monthly schedule of financial obligations has not yet been implemented, the AESO expressed uncertainty as to what additional administrative burden might be imposed, what types of projects the administrative burden might relate to, or how the administrative burden would compare to costs incurred by market participants if financial obligations were to be determined on a less frequent basis. The Commission also recognizes concerns by the DUC regarding the need for customers to be provided sufficient notice respecting any cost overruns that may result in changes to customer contributions. The Commission is satisfied with the AESO’s commitment to continue a discussion with the TFOs and stakeholders as the schedule approach is implemented and to, where practical, seek to mitigate any administrative burdens. The Commission notes that the AESO indicated that it intends to request Commission approval of any proposed revisions to the tariff at a later date, should further discussions result in any proposed changes to the tariff.

**4 Effective dates for tariff**

127. In argument, the AESO noted that, while it had originally requested that its 2011 ISO tariff should be approved to be effective April 1, 2011, by letter dated March 7, 2011, the AESO amended its request to an effective date of July 1, 2011.
128. The AESO noted that in information request AUC.AESO-009,\textsuperscript{51} it advised that it would not be practical for the 2011 ISO tariff to commence on July 1, 2011 for billing purposes while coming into effect on January 1, 2011 for deferral account reconciliation purposes.

Commission findings

129. Some parties commented on the implications of the finding at paragraph 492 of Decision 2010-606 that changes to the customer contribution policy approved for the 2010 tariff should take effect on January 1, 2010, in relation to the need to apply escalators to the 2010 maximum investment levels. The Commission accepts the AESO’s explanation that it would not be practical for the 2011 ISO tariff to commence on July 1, 2011, for billing purposes while coming into effect on January 1, 2011, for deferral account reconciliation purposes. No parties objected to the AESO’s general proposal that the approved 2011 tariff should commence on July 1, 2011, for both billing and deferral account reconciliation purposes.

130. The Commission hereby approves an effective date of July 1, 2011, for the 2011 ISO tariff (Appendix E to the refilled application),

131. Notwithstanding this approval, the Commission notes that certain aspects of the 2011 ISO tariff have not yet been approved and will require a second refiling. The Commission considers that final adjustments to certain subsections of the T&Cs to be refilled have been clearly communicated in this decision and the Commission accepts that adjustments of AESO and market participant billing systems may have been made in anticipation of the July 1, 2011 effective date requested by the AESO. Therefore, the Commission considers that it would not be in the public interest to wait until a final decision has been made on all remaining aspects of the T&Cs that are to be refilled before commencing billing under the rate schedules set out in the 2011 ISO tariff.

132. As set out in Section 3.2 above, the Commission has approved the AESO’s proposal that Section 8 and Section 9 of the T&Cs as set out in Appendix D to the refilled application shall apply from January 1, 2010 until June 30, 2011.

133. The Commission notes that subsection 5(6) of Section 9 of the T&Cs is the only portion of the T&Cs (filed in Appendix E to the refilled application) which has not been approved in this decision. Given this, the Commission approves an effective date of July 1, 2011 for all T&Cs set out in Appendix E of the refilled application, except for subsection 5(6) of Section 9. For greater certainty, the Commission considers that the AESO may commence consideration of requests for waivers of notice in accordance with the wording of Section 5(6) subsection 9 of the T&Cs approved in Section 2.3.4 of this decision prior to the final approval of the AESO’s second refiling.

\textsuperscript{51} Exhibit 32.
5  Order

134.  It is hereby ordered that:

(1)  Except for Section 5(6) of subsection 9 of the terms and conditions of service, the 2011 ISO tariff update provided as Appendix E to the refiled application is approved, effective July 1, 2011, including rates, riders, terms and conditions, and appendices.

(2)  The AESO may apply commence considering requests for waivers of notice prior to final approval of the AESO’s second refilling, in accordance with the wording of Section 5(6) subsection 9 of the terms and conditions of service approved in the Commission directions in this decision.

(3)  The definitions provided as Appendix F to the refiled application are approved, effective July 1, 2011.

(4)  The 2010 construction contribution provisions contained in Section 8 and Section 9 of the 2010 ISO tariff provided as Appendix D of the refiled application are approved, effective from January 1, 2010 to June 30, 2011.

(5)  The 2011 construction contribution provisions contained in Section 8 and Section 9 of the 2010 ISO tariff provided as Appendix D of the refiled application are approved, effective July 1, 2011.

(6)  The AESO shall file a second refiling of the tariff incorporating the changes to subsection 5(6) of Section 9 of the terms and conditions set out in Section 2.3.4 of this decision on or before September 1, 2011.

Dated on June 24, 2011.

The Alberta Utilities Commission

(Original signed by)
Carolyn Dahl Rees
Vice-Chair

(Original signed by)
Bill Lyttle
Commission Member

(Original signed by)
Mark Kolesar
Commission Member
### Appendix 1 – Proceeding participants

<table>
<thead>
<tr>
<th>Name of organization (abbreviation)</th>
<th>counsel or representative</th>
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| Alberta Electric System Operator (AESO) | J. Martin  
R. Sharma  
M. MacLachlan |
| Alberta Direct Connect Consumers Association (ADC) | C. Chekerda |
| ATCO Electric (AE) | L. Keough (Bennett Jones LLP)  
K. Worton (Bennett Jones LLP)  
D. Freedman  
N. Palladino  
J. Janow  
B. Yee |
| AltaLink Management Ltd. (AML) | D. Morris  
E. Manalo |
| British Columbia Hydro and Power Authority (BCH) | C. Searles (Lawson Lundell Barristers & Solicitors)  
L. Manning (Lawson Lundell Barristers & Solicitors)  
J. Sofield |
| Consumers’ Coalition of Alberta (CCA) | J. A. Wachowich  
R. Retnanandan |
| Dual Use Coalition (DUC) | D. Hildebrand (Desiderata Energy Consulting Inc.) |
| FortisAlberta Inc. (FAI) | J. Walsh |
| Industrial Power Consumers Association of Alberta (IPCAA) | S. Fulton  
V. Bellissimo  
M. Forster  
R. (Drazen Consulting Group, Inc.) |
| TransCanada Keystone Pipeline Gp Ltd. (TCKEY) | R. Stevens  
V. Kostesky |
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<td>counsel or representative</td>
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| Office of the Utilities Consumer Advocate (UCA)                        |
| C. R. McCreary (Reynolds Mirth Richards & Farmer)                      |
| S. Mattuli (Reynolds Mirth Richards & Farmer)                           |
| B. Shymanski                                                              |

| The Alberta Utilities Commission (AUC)                                  |
| Commission Panel                                                       |
| C. Dahl Rees, Vice-Chair                                                |
| B. Lyttle, Commission Member                                            |
| M. Kolesar, Commission Member                                            |

| Commission Staff                                                       |
| S. Wakil (Commission Counsel)                                           |
| W. Frost                                                                 |
| P. Hlavac-Winsor                                                       |
| W. A. MacKenzie                                                         |
| K. Schultz                                                              |
| J. Halls                                                                 |
Appendix 2 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Commission has considered the arguments by the UCA, the ADC, the CCA and the AESO regarding notice waivers for energy efficiency projects. The evidence of the AESO suggests that a limited number of market participants would be expected to take advantage of this change in the notice provisions and that the one-time revenue impact appears to be relatively small in comparison to the overall AESO revenue requirement. Consequently, the Commission is persuaded that granting additional discretion to the AESO to waive normal notice requirements may be beneficial in certain circumstances. The Commission, therefore, generally accepts that the proposed changes to subsection 5(6) of Section 9 of the T&Cs as described at paragraph 93 of refiled application are reasonable. However, the Commission considers that the notice waiver provisions would be improved by the inclusion of ADC’s proposal, that qualifying participants must demonstrate that they have taken service from the Alberta grid for a minimum of 20 years, thereby providing additional assurances that there are no stranded investments. As such, the Commission directs the AESO to refile subsection 5(6) of Section 9 of the T&Cs to read as follows:

(6) If the ISO considers that circumstances warrant, the ISO may waive or reduce the requirement for payment in lieu of notice where:

(a) contract capacity is transferred to a system access service of the same market participant at a nearby transmission substation;

(b) transmission system benefits arise from the reduction or termination of contract capacity, which benefits may include relief of regional transmission constraints, removal of capacity limitations which would restrict system access service to other market participants or avoidance of future upgrades to the transmission system; or

(c) the reduction of contract capacity results from an energy or demand reduction initiative of the market participant who has taken service for at least 20 years who:

(i) provides to the ISO a clear, thorough and convincing case, with supporting facts, that demonstrates the energy or demand reduction resulting from the initiative and

(ii) during the ten (10) years prior to the reduction in contract capacity becoming effective, has not increased contract capacity at the point of delivery at which the reduction in contract capacity will occur.

Paragraph 69
2. With respect to the concern of the CCA regarding the potential for this provision to be used by “free-riders,” (that is market participants who reduce their demand or ratchet, but not as a result of any energy efficiency projects), the Commission considers that the risk of “free-riders” should be small so long as the AESO is diligent in investigating requests for notice waivers to ensure that the notice waiver is required to pursue a proposed energy efficiency project, and to ensure that the exit of the market participant giving notice does not give rise to incremental stranded costs that would otherwise be recovered by applying the primary notice provisions of the tariff. However, the Commission directs the AESO to file a report in its next GTA indicating the number of market participants that requested the waiver provided for in the revised subsection 5(6) of Section 9 and the reduction in tariff revenue arising from the approval of any such requests. ... Paragraph 71

3. The AESO is further directed at the time of its next GTA to discuss any changes that should be made to notice provisions in light of its experience with the additional discretion to grant waivers approved in this decision........................................Paragraph 72