

## Notice of variances of decision

January 5, 2021

Please be advised that the Alberta Utilities Commission's Decision 22942-D02-2019 has been varied with the release of Decision 25848-D01-2020.

On November 19, 2020, Decision 22942-D02-2019 was varied with the release of Decision 24932-D01-2020.

Decision 22942-D02-2019 should be read together with Decisions 25848-D01-2020 and 24932-D01-2020 for completeness.

Alberta Utilities Commission



## **Alberta Electric System Operator**

### **2018 Independent System Operator Tariff**

**September 22, 2019**

**Alberta Utilities Commission**  
Decision 22942-D02-2019  
Alberta Electric System Operator  
2018 ISO Tariff Application  
Proceeding 22942

September 22, 2019

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The Commission may, within 30 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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**1 Decision summary**

1. In this decision, the Alberta Utilities Commission must determine whether to approve the Alberta Electric System Operator's (AESO) 2018 ISO (Independent System Operator) tariff.
2. In its application, the AESO indicated that the Commission had concluded that there was a need to address whether and how customer advancement costs can be used to ensure that future system transmission facility upgrades are achieved in both a timely and an economical manner. Its tariff proposal reflected this direction.
3. The principal tariff changes proposed by the AESO are composed of:
  - the parameters of its point of delivery (POD) cost function
  - the value and application of the power factor deficiency charge
  - the method used to calculate a generating unit owner's contribution (GUOC), GUOC rates and when the payment of GUOC is required
  - the metering of distribution connected generation (DCG)
  - amendments to its terms and conditions to:
    - allow it to make contract capacity adjustments;
    - include language creating an ISO preferred alternative if construction of transmission facilities is required for a connection project;
    - require market participants to provide, in a system access service request (SASR), specific information that the AESO will need to plan facilities required to accommodate new connections; and
    - clarify how it determines the classification of a connection project as a system-related or participant-related cost.
4. In addition to the tariff changes proposed by the AESO, AltaLink presented an alternative customer contribution refund proposal.
5. For the reasons set out in the decision, the Commission approved:
  - the continuation of the status quo POD cost function based on contract capacity but excluding the zero MW upgrade projects from the database for calculating the cost function and directed the AESO to conduct a thorough investigation of alternative approaches to calculating the POD cost function;
  - the AESO's proposal to no longer provide waivers of power factor delivery charges but denied its request to increase the charge to \$1,200 per MVA from \$400 per MVA;
  - the AESO's proposed GUOC method and payment timing;



- the majority of the AESO's proposed administrative changes to the T&Cs but denied the AESO's proposal to allow end-use customers to enter into construction commitment agreements directly with transmission facility owners (TFOs);
  - the AESO's proposed adjustments to the gross metering practice and the resulting substation fraction amounts;
  - AltaLink's alternative customer contribution refund proposal; and
  - the AESO's proposed rate treatment for energy storage facilities
6. In addition, the Commission denied:
- the AESO's request to extend the transmission duplication avoidance Rate Rider A1 for an additional 20-year term; and
  - TransAlta's request for cost recovery in respect of the costs of compliance with Alberta Reliability standard CIP-002-AB-5.1.
7. The AESO has been directed to submit a compliance filing in January 2020.

## 2 Introduction

8. On September 14, 2017, the AESO filed an application<sup>1</sup> for approval of its 2018 ISO tariff application (the application, or general tariff application (GTA)). On September 25, 2017, the AESO filed correspondence<sup>2</sup> advising the Commission that it had identified some errors in its application and that it intended to file revised documents. The AESO filed its updated application<sup>3</sup> on October 11, 2017.

9. In the application, the AESO requested:
- (a) approval of the bulk system, regional system, and POD cost functionalization; and the bulk system and regional system cost classification, for 2018, 2019 and 2020 as presented in Section 4 of the application;
  - (b) approval of the proposed 2018 tariff set out in Appendix R of the application, including rates, riders, terms and conditions, and tariff appendixes;
  - (c) confirmation from the Commission that the AESO's entire forecast revenue requirement is subject to deferral account treatment;
  - (d) approval on an interim basis of proposed changes to Rate PSC (Primary Service Credit), and Rider C, Deferral Account Adjustment Rider, as discussed in Section 6 of the application, until such time as the Commission approves Rate PSC and Rider C on a final basis, at the conclusion of the proceeding for the application;

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<sup>1</sup> Exhibit 22942-X0002.

<sup>2</sup> Exhibit 22942-X0031.

<sup>3</sup> Exhibit 22942-X0002.01.

- (e) confirmation from the Commission of its acceptance of the AESO's responses to outstanding directions; and
- (f) such other relief as the Commission deems appropriate.

10. Notice of the application was issued by the Commission on September 15, 2017. Statements of intent to participate (SIPs) were received from the following parties on or before the September 29, 2017, deadline set out in the notice:

- Alberta Direct Connect Consumers Association (ADC)
- AltaLink Management Ltd. (AltaLink or AML)
- ATCO Electric Ltd. (ATCO Electric)
- ATCO Power Canada Ltd. (ATCO Power)
- Balancing Pool
- Capital Power Corporation (Capital Power or CPC)
- Cenovus FCCL Ltd. (Cenovus)
- City of Medicine Hat
- Devon Canada (Devon)
- EPCOR Distribution & Transmission Inc. (EDTI)
- FortisAlberta Inc. (FAI or Fortis)
- Industrial Power Consumers Association of Alberta (IPCAA)
- Office of the Utilities Consumer Advocate (UCA)
- Suncor Energy Inc. (Suncor)
- TransAlta Corporation (TransAlta)
- TransCanada Energy Ltd. (TCE)

11. The Commission accepted additional SIPs filed after the September 29, 2017, deadline, from the following parties:

- Access Pipeline Inc.
- AltaGas Ltd. (AltaGas)
- Alberta Solar Cooperative
- Aura Power Renewables Ltd.
- BluEarth Renewables Inc.
- BowMont Capital and Advisory Ltd.
- Bullfrog Power Inc.
- C&B Alberta Solar Development
- Canada West Ski Areas Association
- Canadian Solar Industries Association (CanSia)
- Canadian Geothermal Energy Association
- Canadian Wind Energy Association
- the Cities of Lethbridge and Red Deer
- Consumers' Coalition of Alberta (CCA)
- Decentralised Energy Canada
- Direct Energy Marketing Limited
- Distributed Generation Working Group (DGWG)

- Dual Use Customers (DUC)<sup>4</sup>
- Energy Storage Canada (ESC)
- ENMAX Energy Corporation (ENMAX Energy)
- ENMAX Power Corporation (ENMAX Power)
- First Nations Power Authority
- Green Cat Renewables Canada Corporation
- Greengate Power Corporation (Greengate)
- Horseshoe Power GP Ltd.
- Keepers of the Athabasca Watershed Society
- Kinder Morgan Canada
- Lionstooth Energy
- Louis Bull Tribe
- Métis Nation of Alberta
- Neyaskweyak Group of Companies (NGCI)
- Solar Krafte Utilities Inc.
- Skyfire Energy Inc.
- Solar Power Investment Cooperative of Edmonton (SPICE)
- Southern Alberta Alternative Energy Partnership
- Turning Point Generation (TPG)

12. On October 4, 2017, the ADC filed a motion objecting to the SIP of AltaLink and submitted that AltaLink should be denied standing in Proceeding 22942.<sup>5</sup> Letters of support for the ADC motion were filed by IPCAA and DUC.<sup>6</sup> Following a process to consider the ADC motion,<sup>7</sup> the Commission issued a ruling on November 27, 2017, which determined that AltaLink had standing to participate fully in Proceeding 22942.<sup>8</sup>

13. In the same ruling, the Commission indicated that it had determined, in response to submissions received in respect of the October 4, 2017 ADC motion, that the coincident metered demand rate design (12 coincident peak (CP) method) would be reviewed in Proceeding 22942. However, in response to comments prepared by the AESO in its October 19, 2017, submission, in which the AESO indicated that it would require additional time to include the 12 CP method in the current proceeding,<sup>9</sup> on December 6, 2017, the Commission requested comments from parties regarding the process steps required to incorporate additional evidence on the 12 CP method in Proceeding 22942.<sup>10</sup>

14. On December 15, 2017, the Commission received a submission from AltaLink<sup>11</sup> in which it indicated that it intended to file evidence regarding the treatment of Fortis customer contributions (the distribution facility owner (DFO) customer contribution issue). As part of its submission, AltaLink requested that the Commission not schedule information requests (IRs)

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<sup>4</sup> The intervention on behalf of the Dual Use Customers was made by Desiderata Energy Consulting Inc. See Exhibit 22942-X0057.

<sup>5</sup> Exhibit 22942-X0060.

<sup>6</sup> Exhibits 22942-X0061 and 22942-X0062.

<sup>7</sup> Exhibit 22942-X0065.

<sup>8</sup> Exhibit 22942-X0089.

<sup>9</sup> Exhibit 22942-X0079.

<sup>10</sup> Exhibit 22942-X0091.

<sup>11</sup> Exhibit 22942-X0098.

until the end of January 2018 to allow AltaLink to consult on its proposals in respect of the DFO customer contribution issue with the AESO and other parties. The Commission requested comments from parties in respect of AltaLink's request in correspondence dated December 21, 2017.<sup>12</sup>

15. On January 19, 2018, the Commission issued a letter<sup>13</sup> regarding the 12 CP method issue and the DFO contribution issue, in which the Commission determined that:

- the DFO Customer Contribution Issue raised by AltaLink would be included in the AESO's tariff proceeding;
- demand transmission service (DTS) rate design is central to the AESO's tariff and there would be no efficiency to conducting a parallel review of DTS rate design issues while at the same time examining the AESO's tariff application since any DTS issues would have to be resolved before a decision on the rest of the tariff could be issued; and
- the AESO must be given an opportunity to supplement its application to address the 12 CP method.

16. In consideration of the foregoing, the Commission suspended the schedule for Proceeding 22942 and granted the AESO time to conduct an analysis, to consult with parties, to prepare evidence on the issues and, if necessary, to file a revised application. The Commission directed the AESO to either file an update to its application or to provide a status update by March 30, 2018. The AESO set up a consultative process in response to the Commission's January 19, 2018, letter.

17. On March 29, 2018, the AESO filed a letter<sup>14</sup> that indicated that its consultations regarding DFO customer contributions and the 12 CP method were still ongoing and that it was not in a position to file an amended application. In its letter, the AESO indicated that it would file a further status update by April 30, 2018.

18. On April 30, 2018, the AESO filed a letter<sup>15</sup> in which it provided an overview of its determinations regarding the 12 CP method and the DFO customer contribution issues as a result of its stakeholder consultations. In this correspondence, the AESO indicated that it had concluded that:

- The 12 CP method requires further consultation over a longer timeframe to determine whether it should be continued, modified or replaced.
- The scope of the DTS rate design review should be expanded to consider regional tariff design.
- Consultations regarding the bulk and regional tariff design it envisioned would take approximately 12 to 18 months and should be conducted outside of Proceeding 22942.

19. In consideration of the AESO's above-noted determinations, the AESO filed a motion requesting that the Commission vary its November 27, 2017, and January 19, 2018, rulings to

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<sup>12</sup> Exhibit 22942-X0104.

<sup>13</sup> Exhibit 22942-X0112.

<sup>14</sup> Exhibit 22942-X0123.

<sup>15</sup> Exhibit 22942-X0129.

remove consideration of the 12 CP method and DTS rate design from the scope of the ISO tariff proceeding. The AESO explained that it had not asked for relief with regard to the DFO customer contribution issue because the Commission had not asked it to amend its application to include an analysis of this matter in its application.

20. On the same date (April 30, 2018), the CCA filed a letter in which it expressed certain concerns with the consultation process proposed by the AESO and proposed an alternate process. In a further submission filed on May 2, 2018,<sup>16</sup> the CCA filed a motion requesting that the consultations on the tariff design matters identified by the AESO be conducted within the context of a Commission tariff proceeding that would be subject to the Commission's negotiated settlement guidelines under Rule 018.<sup>17</sup>

21. The Commission set out a process for consideration of the AESO and the CCA motions in correspondence dated May 17, 2018. After receiving submissions from the AESO and several other interested parties, the Commission issued a ruling on June 29, 2018.<sup>18</sup> In its ruling, the Commission determined that:

- Proceeding 22942 would not include an examination of the 12 CP rate design method that had been approved in Decision 2014-242.<sup>19 20</sup>
- Energy storage tariff matters would be considered in Proceeding 22942 if interested parties wished to prepare evidence.<sup>21</sup>
- Examination of the DFO customer contribution policy remains within the scope of Proceeding 22942.<sup>22</sup>
- The Commission would not issue any direction with respect to the AESO's proposed consultation process in anticipation of a future tariff application, including with respect to the scope, substance, timelines, or composition of any advisory or other committee.<sup>23</sup>
- The AESO was directed to file its next full tariff application before the end of the first quarter of 2020.<sup>24</sup>

22. In response to a direction in the Commission's June 29, 2018, ruling, the AESO filed a letter on July 6, 2018,<sup>25</sup> that indicated that the AESO planned to file an amendment to its application by the end of July 2018. On July 30, 2018, the AESO filed a letter<sup>26</sup> advising the Commission that its amended application would be filed in August 2018.

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<sup>16</sup> Exhibit 22942-X0131.

<sup>17</sup> Rule 018: *Rules on Negotiated Settlements*.

<sup>18</sup> Exhibit 22942-X0156.

<sup>19</sup> Exhibit 22942-X0156, paragraph 33.

<sup>20</sup> Decision 2014-242: Alberta Electric System Operator, 2014 ISO Tariff Application and 2013 ISO Tariff Update Proceeding 2718, Application 1609765-1, August 21, 2014.

<sup>21</sup> Exhibit 22942-X0156, paragraph 40.

<sup>22</sup> Exhibit 22942-X0156, paragraphs 48-52.

<sup>23</sup> Exhibit 22942-X0156, paragraph 64.

<sup>24</sup> Exhibit 22942-X0156, paragraph 67.

<sup>25</sup> Exhibit 22942-X0157.

<sup>26</sup> Exhibit 22942-X0158.

23. The AESO filed an amended application on August 17, 2018.<sup>27</sup> As part of this filing, the AESO provided a cover letter<sup>28</sup> that identified the then current version of appendixes to the amended application, as follows:

- Appendix A - AESO Board Decision 2017-2018-BRP-001<sup>29</sup>
- Appendix B - AESO 2017-2018 Business Plan and Budget Proposal<sup>30</sup>
- Appendix C - Updated Stakeholder Consultation Materials<sup>31</sup>
- Appendix D - Transmission System Cost Causation Study 2018 Update<sup>32</sup>
- Appendix E - Transmission System Cost Causation 2018 Update Workbook<sup>33</sup>
- Appendix F - Updated Point of Delivery Cost Function Report<sup>34</sup>
- Appendix G - Updated Point of Delivery Cost Function Workbook<sup>35</sup>
- Appendix H - 2018 Rate Calculations<sup>36</sup>
- Appendix I - Updated 2018 Bill Impact Analysis<sup>37</sup>
- Appendix J - Updated Transmission Rate Projection Workbook<sup>38</sup>
- Appendix K - 2018 Contribution Policy Investment Levels Workbook<sup>39</sup>
- Appendix L - Examination of Rider C and Deferral Account Reconciliation Methodology Report<sup>40</sup>
- Appendix M - Commission Closure Letter<sup>41</sup>
- Appendix N - AESO 2017 Long-term Outlook<sup>42</sup>
- Appendix O - Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Electricity Market<sup>43</sup>
- Appendix P - Comparison between Electricity Storage and Existing Alberta Site Dispatch Profiles<sup>44</sup>
- Appendix Q - Energy Storage Integration Recommendation Paper and Stakeholder Comments<sup>45</sup>
- Appendix R - Amended Proposed 2018 ISO Tariff<sup>46</sup>
- Appendix S - Updated Blackline Comparison of Proposed and Current Rates, Riders and Appendixes<sup>47</sup>

<sup>27</sup> Exhibit 22942-X0163, AESO Amended application.

<sup>28</sup> Exhibit 22942-X0162.

<sup>29</sup> Exhibit 22942-X0022.

<sup>30</sup> Exhibit 22942-X0023.

<sup>31</sup> Exhibit 22942-X0024.01.

<sup>32</sup> Exhibit 22942-X0025.

<sup>33</sup> Exhibit 22942-X0026.

<sup>34</sup> Exhibit 22942-X0027.01.

<sup>35</sup> Exhibit 22942-X0003.01. This was later updated on December 13, 2018 as Exhibit 22942-X0003.02.

<sup>36</sup> Exhibit 22942-X0004.

<sup>37</sup> Exhibit 22942-X0005.02. This was later updated on December 13, 2018 as Exhibit 22942-X0005.03.

<sup>38</sup> Exhibit 22942-X0126.

<sup>39</sup> Exhibit 22942-X0007.01.

<sup>40</sup> Exhibit 22942-X0008.

<sup>41</sup> Exhibit 22942-X0009.

<sup>42</sup> Exhibit 22942-X0010.

<sup>43</sup> Exhibit 22942-X0011.

<sup>44</sup> Exhibit 22942-X0012.

<sup>45</sup> Exhibit 22942-X0013.

<sup>46</sup> Exhibit 22942-X0014.01.

<sup>47</sup> Exhibit 22942-X0015.01.

- Appendix S.1 - Blackline Comparison of Proposed and Current Rates, Riders and Appendices against Exhibit 22942-X0015<sup>48</sup>
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- Appendix X - Updated Option 4 Point of Delivery Cost Function Workbook<sup>53</sup>
- Appendix Y - Updated Blackline Comparison of Proposed and Current Defined Terms Used in the ISO Tariff<sup>54</sup>

24. On August 17, 2018, ENMAX Energy submitted a letter<sup>55</sup> regarding Information Document (ID 2018-019T), which was issued by the AESO on May 3, 2018. In its letter, ENMAX Energy expressed concern with the changes set out in ID 2018-019T. The AESO had advised that ID 2018-019T was issued to provide additional clarity on the determination of Rate DTS and Rate STS contract capacity for distribution-connected generation. ENMAX Energy advised that this information document had the potential to impose substantial costs on DFOs, adversely affect the economics of distribution-connection generation and introduced additional delays into customer interconnection processes. In light of its concerns, ENMAX Energy proposed that a full AESO consultation in respect of the changes set out in ID 2018-019T, be undertaken in conjunction with the Commission's consideration of the 2018 ISO tariff application. Letters generally supporting the position of ENMAX Energy were filed on August 21, 2018, by the Canadian Solar Industries Association (CanSIA)<sup>56</sup> and by Fortis.<sup>57</sup>

25. On August 22, 2018, the Commission issued a letter establishing a process to receive comments on the submissions of ENMAX Energy, CanSIA, and Fortis regarding the issues raised by ID 2018-019T. Submissions pursuant to this process were received from ENMAX Energy, CanSIA, Fortis and the AESO and from 18 other parties.<sup>58</sup>

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<sup>48</sup> Exhibit 22942-X0165.

<sup>49</sup> Exhibit 22942-X0016.02.

<sup>50</sup> Exhibit 22942-X0017.01.

<sup>51</sup> Exhibit 22942-X0018.02. This was later updated on December 13, 2018, as Exhibit 22942-X0018.03.

<sup>52</sup> Exhibit 22942-X0019.

<sup>53</sup> Exhibit 22942-X0020.01. This was later updated on December 13, 2018, as Exhibit 22942-X0020.02.

<sup>54</sup> Exhibit 22942-X0021.01.

<sup>55</sup> Exhibit 22942-X0161.

<sup>56</sup> Exhibit 22942-X0166.

<sup>57</sup> Exhibit 22942-X0167.

<sup>58</sup> Decentralised Energy Canada, Exhibit 22942-X0169; Skyfire Energy Inc., Exhibits 22942-X0170 and 22942-X0193; Canadian Geothermal Energy Association, Exhibits 22942-X0172 and 22942-X0189; C&B Alberta Solar Development, Exhibits 22942-X0173 and 22942-X0178; Green Cat Renewables Canada, Exhibits 22942-X0174 and 22942-X0175; Canadian Wind Energy Association, Exhibit 22942-X0176; Bullfrog Power Inc., Exhibits 22942-X0177 and 22942-X0179; Southern Alberta Alternative Energy Partnership, Exhibits 22942-X0182 and 22942-X0183; Keepers of the Athabasca Watershed Society, Exhibits 22942-X0184 and 22942-X0185; First Nation's Power Authority, Exhibit 22942-X0186; Alberta Solar Cooperative, Exhibits 22942-X0187 and 22942-X0188; Solar Power Investment Co-Operative of Edmonton, Exhibits 22942-X0190 and 22942-X0196; Aura Power Renewables, Exhibit 22942-X0191; Andres Filella, Exhibit 22942-X0195; Neyaskweyak Group of Companies, Exhibit 22942-X0197; BlueEarth Renewables Inc., Exhibit 22942-X0199; Louis Bull Tribe, Exhibit 22942-X0200; Lionstooth Energy, Exhibit 22942-X0203.

26. In a ruling issued on October 2, 2018,<sup>59</sup> the Commission determined that the subject matter of ID 2018-019T was already within the scope of Proceeding 22942, and it was not necessary to issue a specific direction to the AESO to include this in its application.<sup>60</sup> The Commission further found that the application of the changes in the AESO's metering practices arising from ID 2018-019T should be suspended effective May 15, 2018, and that consideration of the effect of the changes proposed in ID 2018-019T on Rate STS, Rate DTS and metering levels for distribution-connected generation (DCG) was a matter for consideration within the scope of Proceeding 22942.<sup>61</sup>

27. On October 11, 2018, the Commission received a letter from Fortis,<sup>62</sup> which sought further clarification of the scope of the Commission's October 2, 2018 ruling. The AESO filed a submission on October 23, 2018,<sup>63</sup> which provided its understanding of the ruling. On October 29, 2018,<sup>64</sup> the Commission clarified that its October 2, 2018 ruling had the effect of suspending the application of ID 2018-019T and included a direction to the AESO, as of May 15, 2018, to continue to operate in the same manner as it had been operating prior to the issuance of ID 2018-019T. In addition, the Commission's letter clarified that the entire subject matter of ID 2018-019T, including matters related to the determination of the substation fraction, are to be included within the scope of Proceeding 22942.

28. On October 4, 2018, the Commission provided an updated schedule for the remaining process steps for Proceeding 22942.<sup>65</sup> In accordance with this schedule, information requests (IRs) to the AESO were to be filed by November 1, 2018. On November 16, 2018, the AESO requested an extension on the deadline for providing responses to information requests to December 13, 2018. The Commission granted this request in a letter dated November 20, 2018.<sup>66</sup>

29. On November 8, 2018, the Community Generation Working Group (CGWG) filed a letter<sup>67</sup> that requested the Commission to issue a ruling on its eligibility for costs, pursuant to sections 3.2 and 4 of Rule 22: *Rules on Costs in Utility Rate Proceedings* and Section 21 of the *Alberta Utilities Commission Act*. The Commission set out a process for the consideration of this request in correspondence dated November 16, 2018.

30. On December 4, 2018, the Commission issued a letter to the CGWG<sup>68</sup> requesting two budgets showing anticipated expenses for its participation in the proceeding, where one budget included expenses assuming an oral hearing, and one without assuming an oral hearing. The Commission also requested a full discussion of the nature of the CGWG's participation in the proceeding. The CGWG provided the requested information in correspondence filed on

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<sup>59</sup> Exhibit 22942-X0207.

<sup>60</sup> Exhibit 22942-X0207, paragraph 13.

<sup>61</sup> Exhibit 22942-X0207, paragraph 19.

<sup>62</sup> Exhibit 22942-X0209.

<sup>63</sup> Exhibit 22942-X0213.

<sup>64</sup> Exhibit 22942-X0215.

<sup>65</sup> Exhibit 22942-X0208.

<sup>66</sup> Exhibit 22942-X0237.

<sup>67</sup> Exhibit 22942-X0233. The CGWG is comprised of the Canadian Solar Industries Association, First Nations Power Authority, and the Alberta Community and Co-Operative Association.

<sup>68</sup> Exhibit 22942-X0249.



December 7, 2018.<sup>69</sup> The Commission granted the CGWG's application for the eligibility of its costs in a ruling dated December 20, 2018.<sup>70</sup>

31. On November 19, 2018, the Commission received a request from ESC<sup>71</sup> that requested the Commission to issue an advance ruling on its eligibility for costs in Proceeding 22942. The Commission denied ESC's application for costs in a ruling dated December 5, 2018.<sup>72</sup>

32. In addition to granting the AESO's request for an extension to its IR response deadline, in its November 20, 2018 letter, the Commission established a process to consider suggestions on scheduling proposed by the AESO in its November 16, 2018 correspondence. After receiving submissions from several parties, the Commission issued a revised process schedule on December 7, 2018.<sup>73</sup>

33. Intervener evidence was filed by the following parties by the January 15, 2019, deadline set out in the Commission's December 7, 2018, correspondence:

- AltaLink<sup>74</sup>
- ATCO Electric<sup>75</sup>
- The CCA<sup>76</sup>
- Community Generation Working Group (CGWG)<sup>77</sup>
- Distributed Generation Working Group (DGWG)<sup>78</sup>
- Dual Use Customers (DUC)<sup>79</sup>
- Solar Krafte Utilities (Solar Krafte)<sup>80</sup>
- TransAlta Corporation (TransAlta)<sup>81</sup>

34. IRs regarding the above-noted intervener evidence were filed by the AESO, the Commission and other interveners on or before January 28, 2019. Responses to these IRs were filed on February 11, 2019.

35. On January 25, 2019, the Commission received correspondence<sup>82</sup> from Fortis requesting the right to file reply evidence in response to the evidence filed by AltaLink. Following receipt of submissions on this request from AltaLink<sup>83</sup> and a further submission by Fortis,<sup>84</sup> the Commission issued a ruling on January 30, 2019,<sup>85</sup> that authorized Fortis to file evidence and then provided an opportunity for this evidence to be examined by way of IRs from the AESO,

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<sup>69</sup> Exhibit 22942-X0252.

<sup>70</sup> Exhibit 22942-X0313.

<sup>71</sup> Exhibit 22942-X0236.

<sup>72</sup> Exhibit 22942-X0250.

<sup>73</sup> Exhibit 22942-X0251.

<sup>74</sup> Exhibits 22942-X0341 to 22942-X0345.

<sup>75</sup> Exhibit 22942-X0333.

<sup>76</sup> Exhibit 22942-X0335.

<sup>77</sup> Exhibits 22942-X0329 to 22942-X0331.

<sup>78</sup> Exhibit 22942-X0334.

<sup>79</sup> Exhibits 22942-X0336 to 22942-X0340.

<sup>80</sup> Exhibits 22942-X0319 to 22942-X0328.

<sup>81</sup> Exhibits 22942-X0315 to 22942-X0317.

<sup>82</sup> Exhibit 22942-X0346.

<sup>83</sup> Exhibit 22942-X0371.

<sup>84</sup> Exhibit 22942-X0372.

<sup>85</sup> Exhibit 22942-X0374.

the Commission and AltaLink. In accordance with this revised schedule, Fortis filed its evidence on February 11, 2019. IRs in regard to the Fortis evidence were filed by Access Pipeline, the Commission and AltaLink on February 19, 2019. Fortis provided responses to these IRs on February 26, 2019.<sup>86</sup>

36. On February 27, 2019, the Commission received correspondence from AltaLink<sup>87</sup> requesting an opportunity to file rebuttal evidence in response to the evidence filed by Fortis. In a ruling dated March 1, 2019,<sup>88</sup> the Commission granted AltaLink's request. In the ruling, the Commission set out a schedule for receipt of the AESO's rebuttal evidence and for AltaLink to file its rebuttal to Fortis. In accordance with the ruling, the AESO's rebuttal evidence<sup>89</sup> was filed on March 6, 2019, and AltaLink's rebuttal evidence<sup>90</sup> was filed on March 8, 2019.

37. Also in the Commission's March 1, 2019, ruling, the Commission advised parties that based on the amount of evidence received from parties, an oral hearing would be scheduled. In accordance with this determination, an oral hearing was held in Calgary between March 18, 2019 and March 22, 2019.

38. On March 8, 2019, the AESO filed an update to the proposed 2018 ISO tariff to add a provision with respect to its construction contribution policy.<sup>91</sup> On March 17, 2019, the AESO filed an errata and update<sup>92</sup> regarding its amended 2018 ISO tariff application that set out certain changes to the amended application and the AESO's rebuttal evidence.

39. Following the close of the oral hearing, argument submissions were received from the AESO<sup>93</sup> and 15 other parties<sup>94</sup> by April 26, 2019.

40. Reply argument was filed by the AESO<sup>95</sup> and 14 other parties<sup>96</sup> by May 17, 2019.

41. On May 22, 2019, the Commission received a letter from AltaLink<sup>97</sup> requesting leave to file sur-reply argument in light of the nature of certain submissions in Fortis's reply argument.

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<sup>86</sup> Exhibits 22942-X0034 to 22942-X0039.

<sup>87</sup> Exhibit 22942-X0440.

<sup>88</sup> Exhibit 22942-X0441.

<sup>89</sup> Exhibit 22942-X0447.

<sup>90</sup> Exhibit 22942-X0451.

<sup>91</sup> Exhibit 22942-X0453.

<sup>92</sup> Exhibit 22942-X0479.

<sup>93</sup> Exhibit 22942-X0558.

<sup>94</sup> Argument submissions were filed by the University of Alberta (Exhibit 22942-X0542); DUC (and IPCAA and ADC) (Exhibit 22942-X0543); Capital Power Corporation (Exhibit 22942-X0545); TransAlta (Exhibit 22942-X0546); ENMAX (Exhibit 22942-X0547); Solar Krafte Utilities (Exhibit 22942-X0548); CCA (Exhibit 22942-X0549); EDTI (Exhibit 22942-X0550); Greengate (Exhibit 22942-X0551); Access (Exhibit 22942-X0552); ATCO Electric (Exhibit 22942-X0553); AltaLink (Exhibit 22942-X0555); Fortis (Exhibit 22942-X0559); CGWG (Exhibit 22942-X0560); DGWG (Exhibit 22942-X0562).

<sup>95</sup> Exhibit 22942-X0578.

<sup>96</sup> Reply argument submissions were filed by DUC et al. (Exhibit 22942-X0563); Capital Power (Exhibit 22942-X0564); Solar Krafte Utilities (Exhibit 22942-X0566); the CCA (Exhibit 22942-X0567); TransAlta (Exhibit 22942-X0568); the Métis Nation of Alberta (Exhibit 22942-X0569); Greengate (Exhibit 22942-X0570); ENMAX (Exhibit 22942-X0571); ATCO Electric (Exhibit 22942-X0572); the CGWG (Exhibit 22942-X0574); AltaLink (Exhibit 22942-X0575); EDTI (Exhibit 22942-X0576); Fortis (Exhibit 22942-X0579); Access (Exhibit 22942-X0581).

<sup>97</sup> Exhibit 22942-X0582.

After issuing a process letter to consider this request,<sup>98</sup> the Commission received submissions from Fortis<sup>99</sup> and AltaLink<sup>100</sup> on May 31, 2019 and June 6, 2019, respectively.

42. On June 14, 2019, the Commission issued a ruling<sup>101</sup> that granted AltaLink's request to file sur-reply argument. In accordance with this ruling, AltaLink's sur-reply was filed on June 24, 2019.<sup>102</sup>

43. The Commission considers the record for Proceeding 22942 to have closed on June 24, 2019.

### 3 Forecast costs and approval processes

#### 3.1 Legislative scheme

44. Section 119(4) of the *Electric Utilities Act* requires the AESO to prepare a tariff and to apply to the Commission for approval of this tariff. The tariff is composed of two elements: (i) costs and expenses and (ii) the proposed allocation of costs and expenses to rate classes (rate design).

45. Generally, there are four principle categories of costs and expenses incurred by the AESO that are included in its tariff: (i) the AESO's own administrative costs; (ii) ancillary services costs; (iii) transmission line losses; and (iv) costs related to transmission wires (payable under a transmission facility owner (TFO) tariff). The provisions of the *Electric Utilities Act* and the *Transmission Regulation* provide specific direction to the Commission regarding the extent to which the Commission may assess these costs and expenses.

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

47. Similarly, the AESO board approves the costs for ancillary services and transmission line losses. Consequently, Section 3(1) of the *Transmission Regulation* also requires the AESO to consult with market participants directly affected by these costs. However, there is no provision equivalent to Section 46(1) of the *Transmission Regulation* that provides an interested party with the opportunity to argue the reasonableness of these costs before the Commission. Instead, Section 20 of the *Electric Utilities Act* and sections 15, 17, 33 and 34 of the *Transmission Regulation* authorize and, in some instances, direct the AESO to establish rules related to the

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<sup>98</sup> Exhibit 22942-X0585.

<sup>99</sup> Exhibit 22942-X0586.

<sup>100</sup> Exhibit 22942-X0587.

<sup>101</sup> Exhibit 22942-X0588.

<sup>102</sup> Exhibit 22942-X0589.

calculation and recovery of ancillary service costs and costs for line losses.<sup>103</sup> Consequently, where ISO rules are proposed or created for the calculation and recovery of ancillary service costs or the costs for line losses, the Commission's oversight of these costs is addressed through the objection and complaint provisions found in sections 20 and 25 of the *Electric Utilities Act*, respectively.

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

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

### 3.2 Revenue requirement

50. In Section 3 of the application, the AESO explained that its revenue requirement is composed of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration costs. As explained above, the AESO's forecast for these costs are approved through other processes and are not approved as part of this proceeding. The AESO noted that it has the responsibility to collect the costs of ancillary services and line losses under Section 30(4) of the *Electric Utilities Act* while the AESO's own costs are to be collected in accordance with Section 1(1)(g) of the *Transmission Regulation*.

51. The AESO's forecast costs for 2018 are reproduced below:<sup>104</sup>

**Table 1. 2018 forecast, 2017 updated forecast and 2016 recorded cost components**

	2018 forecast	\$ increase (decrease)	% increase (decrease)	2017 updated	\$ increase (decrease)	% increase (decrease)	2016 recorded
Cost component	(\$000)	(\$000)	%	(\$000)	(\$000)	%	(\$000)
Wires	1,719.5	-14.5	-0.8	1,734.0	22.6	1.3	1,711.4
Ancillary services	179.2	60.4	50.8	118.9	25.7	27.5	93.2
Losses	96.8	22.7	30.7	74.1	33.0	80.4	41.1
Administrative	100.8	2.2	2.2	98.7	-1.7	-1.7	100.4
<b>Revenue requirement</b>	<b>2,096.4</b>	<b>70.8</b>	<b>3.5</b>	<b>2,025.6</b>	<b>79.5</b>	<b>4.1</b>	<b>1,946.1</b>

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

<sup>103</sup> Section 30(4)(b) of the *Electric Utilities Act* also permits the recovery of these costs by the AESO fee.

<sup>104</sup> Exhibit 22942-X0163, Amended application, paragraph 29.

53. Wires costs represent approximately 82 per cent of the AESO's 2018 revenue requirement. The AESO explained that it determined wires costs for TFOs using the approach described in Section 2.2 of the AESO's 2017 ISO Tariff Update Application and approved in Decision 22093-D02-2017 and that, specifically, the AESO includes costs that reflect the status of each TFO's application for the effective tariff year of the AESO's revenue requirement.<sup>105</sup>

54. The AESO explained that ancillary services, as defined in the *Electric Utilities Act*, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserves. Operating reserves represent unloaded generating capacity that is available to respond to temporary shortfalls in supply caused by loss of a generating unit, loss of intertie capacity, or fluctuations in load. Ancillary services costs are a function of volume forecasts and market-based commodity pricing forecasts.<sup>106</sup>

55. Ancillary services represent approximately nine per cent of the AESO's 2018 revenue requirement. The AESO noted that the 2018 forecast cost for ancillary services was based on the 2018 forecast of ancillary services volumes and a 2018 forecast average pool price of \$42.58 per megawatt hour (/MWh).<sup>107</sup>

56. The AESO noted that line losses reflect the energy lost on the transmission system when power is transmitted from suppliers to loads. These losses are the residual of the metered generation plus scheduled imports less scheduled exports and metered loads. Like ancillary services costs, line loss costs are a function of volume forecasts and market-based commodity pricing forecasts.<sup>108</sup>

57. Line losses represent approximately five per cent of the AESO's 2018 revenue requirement. The AESO noted that the 2018 forecast cost for transmission line losses was based on the 2018 forecast of loss volumes and a 2018 forecast average pool price of \$42.58/MWh.<sup>109</sup>

58. Administrative costs represent approximately five per cent of the AESO's 2018 revenue requirement. As noted by the AESO in Section 3.5 of the application, "ISO's own administrative costs" are defined in Section 1(1)(g) of the *Transmission Regulation*. The AESO board approves the ISO's own administrative costs in their entirety. However, the amounts recovered through the AESO's tariff include only the transmission-related portions of those costs. Further, the AESO board approval includes the allocation of administrative costs among the three functions of the AESO, namely: transmission, energy market, and load settlement.<sup>110</sup>

### 3.3 Consultation

59. The AESO explained that information from its various consultation initiatives and processes assisted the AESO in developing the proposals included in the application. Stakeholder consultations for the originally filed 2018 ISO tariff were conducted from August 2015 through

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<sup>105</sup> Exhibit 22942-X0163, Amended application, paragraphs 38-39.

<sup>106</sup> Exhibit 22942-X0163, Amended application, paragraphs 43-44.

<sup>107</sup> Exhibit 22942-X0163, Amended application, paragraph 45.

<sup>108</sup> Exhibit 22942-X0163, Amended application, paragraphs 46-47.

<sup>109</sup> Exhibit 22942-X0163, Amended application, paragraph 48.

<sup>110</sup> Exhibit 22942-X0163, Amended application, paragraphs 49-51.

June 2017. The AESO conducted additional stakeholder sessions in March and April 2018 to gather input regarding the 12 CP methodology and the DFO customer contribution policy.<sup>111</sup>

60. The AESO noted that other matters raised during the consultation process prior to the original application being filed, which were not addressed in this application, included the potential for a firm export rate and a review of the construction contribution policy and its relation to the AESO's determination of whether transmission facilities are being designed in excess of the requirements of good electric industry practice (GEIP).<sup>112</sup>

## **4 Discussion of issues**

### **4.1 Wires cost causation study update**

61. Wires costs are discussed in Section 3.2 of the AESO 2018 tariff application.<sup>113</sup> These costs total \$1,719.5 million and represent 82 per cent of the AESO's revenue requirement. The approach the AESO uses to determine wires costs was approved in Decision 22093-D02-2017<sup>114</sup> and is explained as follows:

- (a) If a TFO has received final Commission approval for its applicable tariff, the AESO includes the approved cost for that TFO tariff.
- (b) If a TFO has applied for its tariff, the Commission has issued an initial decision on the application, and the TFO has submitted a refiling in compliance with the decision, the AESO includes the TFO tariff costs included in the refiling.
- (c) If a TFO has applied for its tariff but the Commission has not yet issued an initial decision on the application or an initial decision has been issued but the TFO has not yet submitted its compliance refiling, the AESO includes the most recent of the following: (i) the TFO tariff costs last approved by the Commission on a final basis for the TFO plus 72 per cent of any increase or decrease included in the TFO's tariff application above or below the prior approved costs; and (ii) the TFO tariff costs last applied for by the TFO in a compliance refiling plus 72 per cent of any increase or decrease included in the TFO's tariff application above or below the prior approved costs.
- (d) If a TFO has not yet applied for its tariff, the AESO includes the most recent of the following: (i) the TFO tariff costs last approved by the Commission on either a final or interim basis;

62. The AESO included the 2018 Transmission System Cost Causation Study Update (2018 study) as appendixes D and E to the application. The 2018 study was based on the methodology of the 2014-2016 Alberta Transmission System Cost Causation Study. The AESO stated that:

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<sup>111</sup> Exhibit 22942-X0163, Amended application, paragraphs 22-24.

<sup>112</sup> Exhibit 22942-X0163, Amended application, paragraph 27.

<sup>113</sup> Exhibit 22942-X0002.01, AESO Updated application, paragraphs 35-39. The AESO updated application was later amended on August 17, 2018, Exhibit 22942-X0163.

<sup>114</sup> Decision 22093-D02-2017: Alberta Electric System Operator, 2017 ISO Tariff Update, Proceeding 22093, April 4, 2017.

The AESO is not proposing any changes to the bulk/regional tariff design in this application. The 2018 Update is a mechanical update of the 2014 Study, using the latest available information. As stated above, the AESO requested the Commission to direct that the issue of whether the applied-for bulk/regional tariff design should be changed will not be considered in Proceeding 22942. The Commission ruled that “the scope of Proceeding 22942 will not include an examination of the rate design approved in Decision 2014-242 (12 CP method).”<sup>115</sup> [footnote removed]

...

The 2014 Study, on which the 2018 Update is based, involved analysis in four key areas: (i) functionalization of transmission facility owner (“TFO”) related capital costs, for both existing and planned assets (until 2016); (ii) functionalization of related operations and maintenance (“O&M”) costs; (iii) classification of all costs functionalized as bulk and regional; and (iv) implementation considerations (i.e. discussion of the potential impact of implementing the functionalization and classification results on rates/recovery of the revenue requirement). The 2018 Update involves an identical analysis using additional data that became available since the time the 2014 Study was performed.<sup>116</sup>

63. On January 19, 2018,<sup>117</sup> the Commission ruled that the AESO be given time to conduct an analysis and prepare evidence on the 12 CP method. The Commission also ruled that the DTS rate design affects other aspects of the tariff and is central to this proceeding.

64. Subsequently, the AESO responded in part that:<sup>118</sup>

As further explained in the Update, and based on the AESO’s own assessment and the views presented by stakeholders through the AESO’s consultation, it has determined, among other things, that:

- (a) The 12 CP issue requires further consultation associated with a robust and thorough analysis over a longer timeframe before conclusions can be reached regarding whether the 12 CP methodology should be continued, modified or replaced by an alternative methodology.
- (b) The regional tariff design should also be the subject of consultation in conjunction with consultation regarding the bulk (12 CP) tariff design.
- (c) Further consultation and analysis of the bulk (12 CP) and regional (“Bulk/Regional”) tariff design should be conducted outside of Proceeding 22942 and will require approximately 12-18 months to bring it to conclusion.

65. Based on the above, the AESO submitted a motion requesting the Commission relieve the AESO from filing an amendment concerning the 12 CP methodology and direct that the issue of whether the applied-for Bulk/Regional tariff design should be changed would not be considered in this proceeding.<sup>119</sup>

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<sup>115</sup> Exhibit 22942-X0163, Amended application, paragraph 53.

<sup>116</sup> Exhibit 22942-X0163, Amended application, paragraph 58.

<sup>117</sup> Exhibit 22942-X0112.

<sup>118</sup> Exhibit 22942-X0128, paragraph 6.

<sup>119</sup> Exhibit 22942-X0128, paragraphs 6-7.

66. On June 29, 2018, the Commission ruled:

... the Commission finds the AESO's request to be reasonable. The Commission agrees that an examination of the rate design approved in Decision 2014-242 (12 CP method) requires a thorough analysis and accepts the AESO's submission that it is unable to complete such an analysis within this proceeding. Therefore, the scope of Proceeding 22942 will not include an examination of the rate design approved in Decision 2014-242 (12 CP method).<sup>120</sup>

67. The DUC in its evidence, raised concerns regarding project data that was not utilized in the 2018 study.<sup>121</sup> The DUC made a number of recommendations regarding the 2018 study as described below and submitted that its recommendations would result in increased bulk and regional system charges and reduced POD charges.<sup>122</sup>

68. The DUC provided eight recommendations<sup>123</sup> regarding the 2018 cost causation study:

- (1) functionalize AltaLink substations 1, 2, 4 and 17 as bulk;
- (2) assume AltaLink 138 kV substations with missing data to be POD;
- (3) assume ATCO Electric substation 217 to be bulk;
- (4) assume lines without voltage data to be of a certain voltage based on listing;
- (5) functionalize future substations by obtaining the latest data;
- (6) use the AESO POD project database to forecast POD capital additions for 2016 to 2020;
- (7) trend TFO revenue requirement and O&M costs to calculate the ratio of noncapital cost to total cost; and
- (8) trend the costs from 2010 to 2017 to forecast 2018 to 2020 values.

69. The AESO responded to the DUC's recommendations as follows:<sup>124</sup>

- The AESO agreed with recommendation 1, but nevertheless considers the 2018 Update to be sufficient as filed.
- The AESO did not agree with recommendations 2 to 4 because the costs in question cannot be functionalized objectively.
- The AESO did not disagree with recommendations 5 and 6, but stated these recommendations are outside the scope of the amended application.
- The AESO did not agree with recommendations 7 and 8, because the DUC did not provide evidence that its methodologies would be more accurate and representative of the respective trends.

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<sup>120</sup> Exhibit 22942-X0156, paragraph 33.

<sup>121</sup> Exhibit 22942-X0336, DUC evidence, A12, pages 9-10.

<sup>122</sup> Exhibit 22942-X0336, DUC evidence, A13, page 12.

<sup>123</sup> Exhibit 22942-X0336, DUC evidence, Table 3, page 10.

<sup>124</sup> Exhibit 22942-X0558, AESO final argument, paragraph 139.



70. The DUC subsequently withdrew recommendations 2, 3 and 4.<sup>125</sup>

### Commission findings

71. The Commission notes the following from the AESO's rebuttal evidence:

... the AESO developed its position regarding an update of the 2014 Study and consulted on it with stakeholders. As explained in the 2018 Update, the AESO followed the 2014 Study methodology. The 2018 Update is a mechanistic update of the 2014 Study and the AESO refrained from applying any assumptions not used in the 2014 Study. As stated in Appendix D:

Accordingly unless explicitly stated this 2018 Update utilizes exactly the same data sources, methodologies and calculations as the 2014 Study.

This 2018 Update performs identical analysis using additional data that became available since the 2014 Study was performed.<sup>126</sup> [footnotes removed]

72. The Commission ruling of June 29, 2018, agreed that the cost causation study is a mechanistic exercise, as noted in the quote above. For consistency and to avoid a piecemeal attempt to alter the cost causation study, the Commission agrees with the AESO that the updated 2018 study should refrain from applying any assumptions not used in the 2014 study and should utilize the same data sources, methodologies and calculations from the 2014 study, as practical.

73. Further, the Commission accepts the submission from the AESO that it is working with industry stakeholders as part of the Tariff Design Advisory Group to perform similar studies to those in the DUC's recommendations 5 and 6.

74. The Commission accepts the AESO's 2018 study provided in the AESO's amended application for 2018. However, the Commission directs the AESO to continue the consultation process with respect to the 12 CP issue, the regional tariff design and the bulk tariff design and to investigate and apply, if appropriate, the DUC's recommendations 1, 5 and 6 in its consultative process.

75. The AESO is to incorporate any conclusions or recommendations from the consultation process on these matters in its next tariff application.

## 4.2 POD cost function

76. As explained by the AESO in Section 4.3.2 of its application, the POD cost function is used (i) to classify costs for the POD charge in Rate DTS; and (ii) to establish investment levels for the construction contribution policy in Section 8 of the proposed ISO tariff.<sup>127</sup> The design of the POD charge in Rate DTS is based on a POD cost function methodology that was established during the 2007 ISO tariff application proceeding. The POD cost function was developed using actual connection project data. As the AESO notes in Section 4.3 of its application, the POD cost function was updated in both the 2010 and 2014 ISO tariff applications as well as in the current application.<sup>128</sup>

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<sup>125</sup> Exhibit 22942-X0543, DUC et al., final argument, page 26.

<sup>126</sup> Exhibit 22942-X0447, paragraph 9.

<sup>127</sup> Exhibit 22942-X0163, Amended application, PDF pages 22-23.

<sup>128</sup> Exhibit 22942-X0163, Amended application, PDF page 20.

77. The cost function update included in this application has a similar structure to the update included in the AESO's previous tariff application. However, compared to the previous update, in the estimation of the parameters of the POD cost function there are differences in (i) the database that is used; (ii) the inflation factors used to adjust cost data from previous years to 2018; and (iii) the actual data and variables that are included in the estimation. Each of these aspects of the analysis is considered below. In addition, details concerning the form of the cost function and the estimation methodology that is used, which form the necessary background for considering the third of these aspects, are also provided.

#### 4.2.1 POD cost function database

78. As explained by the AESO in the revised Appendix F of its application,<sup>129</sup> the POD cost function is based on actual data for connection projects that result from requests by market participants for system access service. Connection projects involve the construction of transmission facilities for the connection of a market participant's facilities to the existing transmission system and may be either "greenfield" projects or "upgrade" projects. Greenfield projects are those that require the construction of a new substation to provide system access service, while upgrade projects are those that require the construction of additional facilities at an existing substation. Pursuant to a Commission direction in Decision 2014-242, customer-owned projects are excluded from the POD cost function database.<sup>130</sup>

79. As further explained in revised Appendix F of the application, the database for the current application included:

- (a) 92 greenfield load-only projects with in-service dates in 1999 to 2017 (compared to 81 in the previous application);
- (b) 175 upgrade load-only projects with in-service dates in 1999 to 2017 (compared to 114 previously). Of these 175 upgrade load-only projects in 1999 to 2017, 21 projects were for contract increases of zero MW (compared to 9 projects in the previous application);
- (c) 18 pre-AESO load-only projects with in-service dates in 1987 to 1999 (the same as in the previous application).

The AESO refers to projects in categories (a) and (b) as "AESO-era" projects, which represent data points for which the AESO has reasonably detailed facilities, cost, and contract information. In contrast, the 18 projects in category (c), referred to as "pre-AESO" projects, and which the AESO describes as having been initially included in the databases used in prior ISO tariff applications and "as the smallest and largest projects, to allow development of a more robust cost function, and ... [are] retained in the current database for the same reason and to add stability to the cost function through successive ISO tariff applications. The cost and contract information available for pre-AESO projects is very limited."<sup>131</sup>

80. Subsequent to the AESO's amended application, but prior to the hearing, the AESO revised the projects included in the database as set out in the tab labelled "BLACKLINE" in the revised Appendix G.<sup>132</sup> Specifically, as noted in this tab, project data in all three categories were

<sup>129</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report.

<sup>130</sup> Decision 2014-242, paragraph 208 (Direction 1).

<sup>131</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 6.

<sup>132</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook.

updated to reflect updated information and to reflect the detailed review noted in the response to AESO-DUC-2018OCT31-006.<sup>133</sup> As a result, nine greenfield projects were removed while eight were added, for a net loss of one greenfield project. In addition, eight upgrade projects were removed while 22 were added, for a net increase of 14 upgrade projects. As a result, the final database set out in revised Appendix G includes 298 projects that comprise:

- (a) 91 greenfield load-only projects with in-service dates in 1999 to 2017;
- (b) 189 upgrade load-only projects with in-service dates in 1999 to 2017. Of these 189 upgrade load-only projects, 24 projects were for contract increases of zero MW; and
- (c) 18 pre-AESO load-only projects with in-service dates in 1987 to 1999.

#### 4.2.2 Inflation factors and adjustments

81. For each POD, escalators are used to adjust costs from the year they were incurred to 2018. As in previous applications, these escalators, in percentage terms, are based 65 per cent on the percentage growth in Alberta Average Weekly Earning (AWE) and 35 per cent on the percentage growth in the Alberta all-item Consumer Price Index.<sup>134</sup> In response to a Commission IR, the calculations were modified to account for various Statistics Canada series that had been terminated and to link the terminated series to values of replacement series issued subsequently.<sup>135</sup>

#### 4.2.3 Functional form specification for the POD cost function and estimation methodology

82. In order to estimate the POD cost function, it is necessary to specify a functional form and to determine how estimation is to proceed. Based on the approach used in previous ISO tariff applications, the POD cost function is assumed to follow a power function, which has the form:<sup>136</sup>

$$COST_i = \alpha MW_i^\beta,$$

which can be written in logarithmic form as:

$$\ln(COST_i) = \ln(\alpha) + \beta \ln(MW_i),$$

or alternatively as:

$$\ln(COST_i) = \alpha^* + \beta \ln(MW_i),$$

where  $COST_i$  is the cost associated with the  $i^{\text{th}}$  POD;  $MW_i$  is the megawatts associated with the  $i^{\text{th}}$  POD;  $\alpha$  (or  $\alpha^* = \ln(\alpha)$ ) and  $\beta$  are unknown parameters that are to be estimated, and  $\ln(\cdot)$  is the natural logarithm of the term in parentheses.

<sup>133</sup> Exhibit 22942-X0283, AESO-DUC-2018OCT31-006, PDF pages 12-13. The changes reflect responses detailed in Exhibit 22942-X0283, AESO-DUC-2018OCT31-003-005, PDF pages 6-11.

<sup>134</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “2018 Escalator.”

<sup>135</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-045, PDF pages 98-100.

<sup>136</sup> See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “Power Curve Model.”

83. Estimation of the POD cost function specified above requires data on *COST* and *MW* for various PODs. For the 91 greenfield load-only projects, and for the 18 pre-AESO load-only projects, this information is known, although to facilitate the analysis all costs must be expressed in the same units; specifically, 2018 dollars and MW. Initially, the POD cost function is estimated using these 109 data points to yield what is referred to here as the Greenfield Regression (or the Power Curve for Greenfield Projects). For later use, the estimated Greenfield Regression is:<sup>137</sup>

$$COST_i = 2.6654 MW_i^{0.5429}.$$

84. For the 189 upgrade load-only projects, including the 24 projects where the amount of MW did not change with the upgrade, the initial cost of the POD (prior to the upgrade) is unknown, although the initial MW are known. However, the cost and the change in MW associated with the upgrade is known in each case. Therefore, for these PODs, total MW can be calculated as the sum of the initial MW and the change in MW due to the upgrade, but total *COST*, which is the sum of the unknown initial cost and the known upgrade cost, is unknown. Consequently, data points corresponding to upgrades cannot be used directly in the estimation of the POD cost function.

85. To utilize the data points pertaining to upgrades, the AESO uses the following approach:<sup>138</sup>

- (a) Using the estimated Greenfield Regression, for each upgrade project, substitute in the initial MW associated with that project to obtain a predicted value of *COST* prior to the upgrade.
- (b) For each upgrade project, add the known upgrade cost to the predicted value of cost prior to the upgrade to obtain an estimate of total cost after the upgrade.
- (c) Re-estimate the POD cost function using the 109 data points used in the Greenfield Regression as well as the total cost and total MW (initial MW plus change in MW due to the upgrade) associated with the 189 upgrade data points. This yields a new estimated POD cost function, involving a new set of estimated regression parameters.
- (d) Using the new estimated POD cost function from the previous step as the “new” Greenfield Regression, repeat steps (a)-(c). This is referred to as an iteration.
- (e) Repeat step (d) until the estimated parameters are the same in two successive iterations; that is, until the change in the estimated parameters from one iteration to the next is less than 0.001 per cent.

86. In Revised Appendix G, the process described above requires 15 iterations, and yields the following estimated POD cost function:<sup>139</sup>

<sup>137</sup> See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “Greenfield.”

<sup>138</sup> See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tabs labelled “GF + UG Iteration 1” to “GF + UG Iteration 15.”

<sup>139</sup> See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tabs labelled “GF + UG Iteration 15” and “Cost Function.”

$$COST_i = 2.7984 MW_i^{0.5533}.$$

87. Using the nomenclature provided above, for the logarithmic equation that is estimated, the parameter estimates are  $\alpha^* = 1.02903$ , with an estimated standard error of 0.10085, and  $\beta = 0.5533$  with an estimated standard error of 0.03136.<sup>140</sup> The intercept in the power equation is obtained as  $\alpha = \ln(1.02903) = 2.7984$ , which would therefore have an approximate standard error of  $\ln(0.10085) = 1.106$ . Hence, the parameter estimates in the estimated POD cost function, 2.7984 and 0.5533, differ from the estimates in the Greenfield Regression, of 2.6654 and 0.5429, by 0.1330 and 0.0124, respectively. These differences are considerably less than the size of the corresponding estimated standard errors, of 1.106 and 0.03136, indicating that the parameter estimates in the estimated POD cost function are statistically not significantly different from those in the Greenfield Regression.<sup>141</sup>

#### 4.2.4 Data and variables used in POD Cost Function estimation

88. In estimating the POD cost function specification explained above, there are choices to be made with respect to the data (PODs) that are actually included in the estimation and the particular variables that are used for *COST* and *MW*. For example, data on capacity (*MW*) can be the contracted amount or the installed amount. Further, the selected capacity variable could differ as between greenfield projects and upgrade projects. As shown in Table F.4-3 in Appendix F, across all projects contract capacity is just over one-half (54.55 per cent) of installed capacity,<sup>142</sup> so results will likely differ depending on which variable is included in the regression analysis. In terms of data selection, with upgrade projects one possibility is to exclude upgrades that involve positive costs but no change in capacity, while an alternative is to include all upgrade projects regardless of the size of the capacity change. As delineated in Table F.4-1 in Appendix F, the AESO considered four options for the data and variables included in the POD cost function estimation. Subsequently, in the AESO rebuttal evidence, the list of options was expanded to include a further five options identified by the DUC during the proceeding.<sup>143</sup> These are shown in Table 2, with the first four options being those considered by the AESO in its application.

**Table 2. POD cost function options (updated)**

Option		Greenfield projects capacity	Upgrade projects capacity	Zero MW upgrade projects	Pre-AESO projects	Costs based on:
#1	As applied for in 2014 application and in the current application	Contract	Contract*	Include	Include	Participant-related costs
#2	Current practice	Contract	Contract	Remove	Include	Participant-related costs

<sup>140</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “GF + UG Iteration 15.”

<sup>141</sup> Alternately, the estimated standard errors from the Greenfield Regression could be used to make this comparison of the estimated parameters in the two estimations, but since the estimated standard errors from the Greenfield Regression are approximately twice as large, this would not change the conclusion. See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “Greenfield.”

<sup>142</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 13.

<sup>143</sup> Exhibit 22942-X0447, AESO rebuttal evidence, Table 1, PDF pages 9-11.

Option		Greenfield projects capacity	Upgrade projects capacity	Zero MW upgrade projects	Pre-AESO projects	Costs based on:
#3	As requested in Decision 2014-242	Contract	Installed	By using installed, zero MW upgrade projects are included	Include	Participant-related costs
#4	Not asked for previously	Installed	Installed	By using installed, zero MW upgrade projects are included	Include	Participant-related costs
#4a	Option #4 with zero MW projects removed	Installed	Installed	Remove	Include	Participant-related costs
#4b	Option #4 with pre-AESO projects removed	Installed	Installed	By using installed, zero MW upgrade projects are included	Remove	Participant-related costs
#5	Combines #4a & #4b – zero MW and pre-AESO projects removed (per the DUC evidence)	Installed	Installed	Remove	Remove	Participant-related costs
#6	Create a single substation cost function such that all upgrade costs and capacity increases are combined as a single substation (per the DUC IR responses to AUC)	Installed	Installed – combine upgrades into the single substation	Remove	Remove	Participant-related costs
#7	Option 6 amended to use AESO investment amounts instead of participant-related costs.	Installed	Installed – combine upgrades into the single substation	Remove	Remove	AESO investment amounts

Source: Exhibit 22942-X0447, AESO rebuttal evidence, Table 1, PDF pages 9-11, and Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, Table F.5.0, PDF page 15.

\*For Option #1, upgrade projects capacity is stated as “Include” in the AESO rebuttal evidence, but is correctly labelled as “Contract” in Revised Appendix F.

89. The AESO’s initial focus on the first four options in Table 2 is grounded in the methodology used in previous ISO tariff applications and Commission decisions resulting from those applications. Option #1, using contract capacity for both greenfield and upgrade projects, and including the pre-AESO projects, as well as upgrade projects that involved no change in contract capacity, is the option that the AESO applied for in its 2014 tariff application, in Proceeding 2718. However, in the decision resulting from that proceeding, the Commission did not agree with the use of this option. In Decision 2014-242, the Commission stated:<sup>144</sup>

In the Commission’s view, a central purpose of the POD project database is to determine the correlation between cost and capacity and to ensure this is appropriately reflected in

<sup>144</sup> Decision 2014-242, paragraph 258.

the POD cost function and the slope of the cost curve. The AESO's practice of using total project costs but only contracted capacity introduces an element of distortion because it does not match the actual capacity created by the actual expenditure of funds.

90. Subsequently, in Direction 2 of Decision 2014-242, the Commission directed that:<sup>145</sup>

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

91. However, the AESO's work to respond to Direction 2 led to unanticipated effects that were identified in various information requests in the compliance Proceeding 3473. As the AESO notes in Section F.1 of Appendix F of its current application, various interveners "raised concerns with the consistency of developing a cost function based on contracted capacity for greenfield projects on the one hand, versus capacity made possible by upgrade projects on the other."<sup>146</sup>

92. In its compliance filing decision in Proceeding 3473, the Commission found:<sup>147</sup>

The Commission has reviewed the AESO's response to Direction 2 and finds that it has resulted in unanticipated effects that could not have been known at the time of Proceeding 2718. The AESO's proposal to delay the implementation of Direction 2 until the matter can be thoroughly explored is reasonable and both the UCA and Devon agree with this approach.

With respect to the 2014 ISO tariff, the Commission finds that the AESO's proposal to use the Rate DTS point of delivery charges and maximum investment levels shown in Table 1 and Table 2 above, described as "Greenfield and Update excluding 0 MW," to be reasonable and approves this approach.

93. Option #2 in Table 2 is the option described in the compliance filing decision as "Greenfield and Update excluding 0 MW," which the Commission approved. Appendix F of the current application, involving consideration of options #1, #3 and #4 in Table 2, as well as the current practice described in Option #2, is described by the AESO as "the AESO's thorough exploration of the matter of using contract or installed capacity to determine the POD cost function."<sup>148</sup>

94. Option #3 involves a mix of contract capacity (for greenfield projects) and installed capacity (for upgrade projects) and, as discussed above, previously resulted in "unanticipated impacts." Consequently, as explained by the AESO in Appendix F, "the AESO did not put further work in assessing ways to address the issues raised in Proceeding 3473. As well, stakeholders supported Option #4 as one way to address the "unanticipated impacts" of Option #3. As a result, no further work was done by the AESO to develop a cost curve based on

<sup>145</sup> Decision 2014-242, paragraph 260.

<sup>146</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF pages 4-5.

<sup>147</sup> Decision 3473-D01-2015 (Errata): Alberta Electric System Operator Errata to 2014 ISO Tariff Compliance Filing Pursuant to Decision 2014-242, Module 1, paragraphs 31-32.

<sup>148</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 5.

a mix of contract capacity for greenfield load-only projects and installed capacity for load-only upgrade projects.”<sup>149</sup>

95. As stated by the AESO in its application, Appendix F “thoroughly explores the four different methodologies [options #1 to #4], the resulting rates and investment, and an evaluation of the pros, cons and impacts of each option.”<sup>150</sup> Specifically, revised Appendix F includes details of the AESO’s stakeholder consultation concerning the POD cost function, as well as a summary of stakeholder feedback regarding support, opposition or indifference to potential qualitative criteria the AESO presented to evaluate the four options. A large degree of indifference to many of these criteria by stakeholders led the AESO to reduce the evaluation criteria to seven criteria. These included:<sup>151</sup>

- (i) Maintaining alignment between rates and investment – trying to avoid having POD charges based on installed capacity but regional charges based on contract capacity;
- (ii) Maximizing the number of projects in the database;
- (iii) The degree of the relationship between contract and installed capacity – determining if there is a measurable difference using POD cost versus installed capacity rather than contract capacity;
- (iv) The lumpiness of installed capacity and standard transformer sizes – using standard transformer sizes, as reflected in installed capacity, could reduce the ability of investment levels to provide price signals, and affect fairness, objectivity and equity;
- (v) The number of assumptions required to determine contract and installed capacity – treating installed capacity as only the transformation capacity;
- (vi) Rates reflect true costs per MW and send the “right” price signal – based on statistical accuracy (R-squared), resulting rate and investment; and
- (vii) The fairness of treatment of customers with charges based on two different approaches – if rates are now based on installed capacity compared to contract capacity previously.

96. The AESO provided the summary evaluation comparison shown in Table 3. In its application, the AESO only ranked options #1 to #4; however, the other options are included in its rebuttal evidence. The AESO noted that it had insufficient information to evaluate and rate options #6 and #7 with respect to the first five criteria.<sup>152</sup>

<sup>149</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 15.

<sup>150</sup> Exhibit 22942-X0163, Amended application, PDF page 20.

<sup>151</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF pages 10-14.

<sup>152</sup> Exhibit 22942-X0447, AESO rebuttal evidence, PDF page 11.



**Table 3. AESO evaluation of POD cost function options (updated)<sup>153</sup>**

Criterion	#1	#2	#3	#4	#4a	#4b	#5	#6	#7
Maintain alignment between rates and investment	3	3	1	3	3	3	3		
Maximize number of projects in database	3	2	3	3	2	2	1		
Degree of relationship between contract and installed capacity	2	2	1	2	2	2	2		
Lumpiness of installed capacity	3	3	1	1	1	1	1		
Number of assumptions	3	3	1	1	1	1	1		
Determine “right” price signal	2	2	-	3					
Greenfield R <sup>2</sup>	0.3687	0.3687	n/a	0.4361	0.4055	0.4055	0.3296	0.4828	0.3692
Greenfield + Upgrade R <sup>2</sup>	0.5294	0.5126	n/a	0.6123	0.6218	0.5346	0.5558		

Source: Exhibit 22942-X0447, AESO rebuttal evidence, Table 2, PDF pages 11-12, and Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, Table F.6.1, PDF page 22.

97. Based on this evaluation table, the AESO preferred Option #1 based on qualitative measures (the first five criteria in Table 3). The AESO noted concerns with removing projects from the database (that is, the zero MW upgrade projects in Option #2) “that do reflect how market participants respond to the price signals of investment and rates. If DFOs are not responding appropriately or are responding differently than direct-connect market participants to the ISO tariff investment and rate price signals, removing DFO data points from the database for this reason will not address the fundamental investment policy issue.”<sup>154</sup>

98. While noting the higher  $R^2$  value (goodness of fit measure of the estimated POD cost function to the data points) for Option #4, the AESO argued that “the increase in predictive ability does not outweigh the difficulty in making the installed capacity assumption, difficulty in sending price signals to market participants given that TFOs have a preference for standard equipment sizes, i.e., lumpiness of the installed capacity, and the fairness of moving to an approach where market participants are faced with charges based on installed capacity, but investment based on contract capacity.”<sup>155</sup> Based on this analysis, the AESO preferred Option #1, using all data, including the zero MW upgrades, and contract capacity for all projects.

#### 4.2.5 How the estimated POD cost function is used

99. In order to provide context for understanding why certain aspects of the cost function specification are preferred by the AESO, and to demonstrate particular issues that arise with the POD cost function analysis, the Commission finds it helpful in this section to set out the steps that, utilizing the POD cost function parameter estimates, are followed once the POD cost function has been estimated.

<sup>153</sup> Note: A value of 3 is the highest rating in terms of meeting a criterion. The seventh criterion listed previously, concerning fairness, is considered separately.  $R^2$  values are rounded to four digits.

<sup>154</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 23.

<sup>155</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 23.

100. The estimated POD cost function using Option #1, as provided in Revised Appendix G, is:<sup>156</sup>

$$COST_i = 2.7984 MW_i^{0.5533},$$

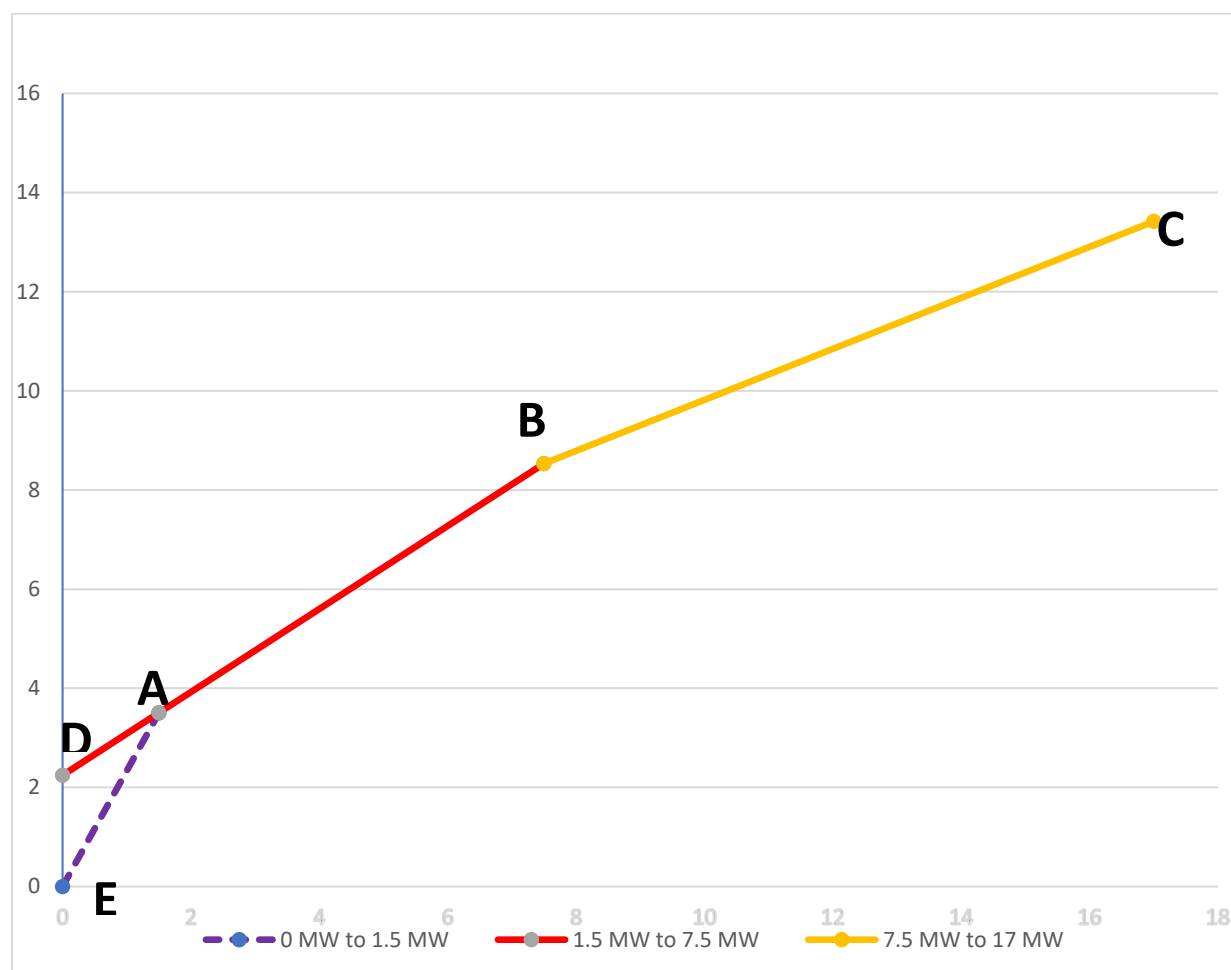
which is a nonlinear function, although, as noted previously, it is linear when the variables,  $COST$ , measured in millions of dollars, and  $MW$  are both converted to natural logarithms as:

$$\ln(COST_i) = \ln(2.7984) + 0.5533 \ln(MW_i).$$

Nevertheless, the first step undertaken by the AESO subsequent to obtaining the estimated POD cost function is to convert it to a piecewise linear function by determining estimated cost at five pre-specified levels of MW, namely 1.5 MW, 7.5 MW, 17 MW, 40MW and 122.8 MW, as established in the 2007 ISO tariff proceeding.<sup>157</sup> By drawing a series of line segments that join the costs at these points, the result is a function that is piecewise linear; that is, it is linear between each two successive points, but where the slope of each successive segment is decreasing, reflecting the economies of scale associated with larger connection projects. This is shown in Figure 1 below, where the points labelled “A,” “B” and “C” in Figure 1 show estimated costs at 1.5 MW, 7.5 MW and 17 MW, respectively, and the line segments from “A” to “B” and from “B” to “C” show the piecewise linear segments of what will be referred to here as the linearized POD cost function. Although the power function form of the POD cost function that is estimated implies that  $COST$  equals zero if  $MW = 0$ , rather than joining the estimated cost at 1.5 MW to a cost of zero at zero MW to obtain the first segment of the linearized POD cost function, that is, between points “E” and “A” in Figure 1, the AESO uses a different procedure. Specifically, the line segment joining the estimated cost at 1.5 MW and the estimated cost at 7.5 MW, the segment from “A” to “B” in Figure 1, is extended back, maintaining its slope, until it reaches the point at which  $MW = 0$ , that is, the point labelled “D” in Figure 1. The segment from “D” to “A,” with the same slope as the segment from “A” to “B,” then forms the first part of the linearized POD cost function.

<sup>156</sup> See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tabs labelled “GF + UG Iteration 15” and “Cost Function.”

<sup>157</sup> Decision 2007-106: Alberta Electric System Operator, 2007 General Tariff Application, Application 1485517-1, December 21, 2007, PDF page 61.

Figure 1. Linearized POD cost function (cost versus MW)<sup>158</sup>

101. The linear segments subsequently determine rate tiers. For use in these rate calculations, the AESO determines the slope of each line segment as the difference in vertical height (costs) of the two endpoints of that segment divided by the horizontal distance between the two endpoints (MW). In this way, the slope indicates the constant incremental cost per MW within each linear segment or rate tier relative to the previous rate tiers. The value (COST) at point “D” in Figure 1 is determined as COST at point “B” less the product of the slope of the line segment from “A” to “B” and the horizontal distance from “D” to “B” of 7.5 MW. These calculations for Option #1 as shown in Appendix H of the application, are provided below in Table 4. The value of COST when  $MW = 0$ , is referred to in the table as the intercept.

<sup>158</sup> Source: Commission representation based on lines 2, 3 and 4 of Exhibit 22942-X0004.01, Revised Appendix H – 2018 Rate Calculations, tab labelled “H-6 POD Classification,” which is reproduced below as Table 4.

**Table 4. Determination of rate tiers for Option #1<sup>159</sup>**

Appendix H — 2018 Rate Calculations									
POD Cost Function and POD Cost Classification									
Line No.	Description	Reference	A	B	C	D	E	F	
			Customer	Demand					Total
1	Power Function	As applied for	Costs (\$ million) =	2.7984	x	MW ^	0.5533		
2	Data Points (MW)	2007-106	1.5 MW	7.5 MW	17 MW	40 MW	122.8 MW		
3	Calculated Values (\$ 000 000)	Lines 1 and 2	\$ 3.502	\$ 8.532	\$ 13.418	\$ 21.543	\$ 40.071		
			Customer	Demand					Total
			Fixed	<= (7.5xSF) MW	<= (17xSF) MW	<= (40xSF) MW	> (40xSF) MW		
	POD Cost Classification								
4	Intercept and Slopes (\$ 000 000)	Lines 2 and 3	\$ 2.245	\$ 0.838	\$ 0.514	\$ 0.353	\$ 0.224		
5	Determinants (cust-months, MW-months)	Table C-10	5,292.1	36,451.3	34,336.1	43,074.6	44,050.0		
6	Total Cost Function Costs (\$ 000 000)	Line 4 x Line 5	\$ 11,880.8	\$ 30,546.2	\$ 17,648.8	\$ 15,205.3	\$ 9,867.2	\$ 85,148.3	
7	Cost Classification (%)	Line 6 ÷ Col F	14.0%	35.9%	20.7%	17.9%	11.6%	100.0%	
Note: 1. The "Customer" billing determinant at Line 5 Col A is the sum over all Rate DTS market participants of the substation fraction for each Rate DTS market participant									
2. The "Demand" billing determinants at Line 5 Cols B-E are the sums over all Rate DTS market participants of billing capacity within the bounds indicated as (amounts x substation fraction) for each Rate DTS market participant									

102. Multiplication of the intercept and slopes for each line segment (Line 4 of Table 4) by the corresponding billing determinants, shown in Line 5 of Table 4, yields total costs for each rate tier, as shown in Line 6, with the total over all tiers shown in the right-most column of Line 6. The percentage of these total costs that fall within each category is shown in Line 7 of Table 4.

103. The percentages from Line 7 of Table 4 are the only information from the POD cost function estimation and analysis that are used in setting rate DTS. Specifically, as shown in the calculations in Appendix V, in tab "V-8 DTS Rate," the values in Column "I" for DTS POD wire charges are calculated for each rate tier (that is, as defined by the ranges in each column in the lower part of Table 4, including the customer (fixed) charge) as total POD wire charges, excluding flat usage charges, multiplied by the percentages in Line 7 of Table 4. Calculations for non-wires charges for each tier except the customer charge include the wire charges for the corresponding tier and, therefore, also depend on the percentages from Line 7 of Table 4. Total charges are the sum of the wires and non-wires charges, which are then divided by the billing determinants for each rate tier to yield the POD charges for each rate tier, as shown for Option #1 in Table 5, below.

<sup>159</sup> Exhibit 22942-X0004.01, Revised Appendix H – 2018 Rate Calculations, tab labelled "H-6 POD Classification". Also contained in Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled "V-6 POD Classification."

**Table 5. POD charges for each rate tier using Option #1<sup>160</sup>**

Point of delivery charge	(\$)
POD charge – customer × SF	11,480
POD – Demand ≤ (7.5 × SF) MW	4,285
POD – Demand > (7.5 × SF) to ≤ (17×SF) MW	2,628
POD – Demand > (17 × SF) to ≤ (40×SF) MW	1,805
POD – Demand > (40 × SF) MW	1,145

Note: “SF” refers to substation fraction; the charges provided in each line are applied to billing capacity within the bounds defined as amounts multiplied by the substation fraction for each Rate DTS customer.

104. Apart from contributing to the shares of costs allocated to each tier, the estimated POD cost function also plays a role in determining the investment for each project. Specifically, for each of the 298 projects included in the database, by substituting the number of MW in the estimated POD cost function, the estimated cost is calculated separately for the number of greenfield MW and for the total number of MW (GF+UG), with the difference representing the cost for the number of upgrade MW.<sup>161</sup> These three estimated costs for each project are referred to as “investments.” The “maximum investment” is calculated as the greenfield investment for greenfield projects and as the upgrade investment for upgrade projects.

105. Next, the actual project costs are compared to these investment amounts. Project costs are known for greenfield projects and for the upgrade component, but not the greenfield component of upgrade projects. For the greenfield component of upgrade projects, an estimate of project cost is obtained by substituting the number of greenfield MW in the estimated POD cost function.<sup>162</sup> The greenfield investment amount for each greenfield project and the upgrade investment amount for each upgrade project is then reset to equal the lesser of the actual investment amount and the maximum investment amount. The difference, if any, between the actual investment amount and the maximum investment amount is defined as the unused investment. Finally, for projects of each type, the contribution is calculated as the difference between the actual cost and the reset investment amount.<sup>163</sup>

106. Based on the sum over all projects of the reset investment amounts and the contribution amounts, certain coverage measures are calculated. The key measure for the subsequent analysis

<sup>160</sup> Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “POD Options Summary.” The detailed calculations are shown in the tab labelled “V-8 DTS Rate,” as well as in Exhibit 22942-X0004.01, Revised Appendix H, Rate Calculations, tab labelled “H-8 DTS Rate.”

<sup>161</sup> See Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “Investment Proposed,” columns “M”-“P” for these calculations for Option #1. The same calculations appear in Exhibit 22942-X0007.02, Revised Appendix K – Investment Levels,” also in the tab labelled “Investment Proposed,” in columns “M”-“P,” except that here projects are re-ordered in terms of increasing size of maximum investment.

<sup>162</sup> The estimated parameters used are those from the penultimate iteration (i.e., based on the parameters from iteration 14 in Appendix G) of the POD cost function estimation, but since the iterative process stops when there is no change in the parameters, these are the same as the estimated parameters from the final iteration (iteration 15). See Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tabs labelled “GF + UG Iteration 14” and “GF + UG Iteration 15.”

<sup>163</sup> Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “Investment Proposed,” columns “R”-“V.”

is the ratio of the investment amounts for greenfield and upgrade projects to the total investment and contribution costs of greenfield and upgrade projects, which is expressed as a percentage. The denominator of this ratio is also equal to the sum of greenfield costs for greenfield projects and upgrade costs for upgrade projects.

107. Next, the multiplier is defined as a constant number that is to be multiplied by the intercept and each slope value shown in Line 4 of Table 4. The numerical value of this multiplier is defined to be the value that is required for the investment amounts for greenfield and upgrade projects, summed over all projects, to equal 60 per cent of the total investment and contribution costs of greenfield and upgrade projects, also summed over all projects. To determine this numerical value, the calculations described above, concerning investment and contribution amounts for each project, are recalculated for all possible values of the multiplier ranging from 0.0 to 7.0, in increments of 0.01. With Option #1, the 60 per cent investment share is achieved with a multiplier of 0.83.<sup>164</sup>

108. Finally, based on investments involving a 20-year lifespan, the resulting terms from the product of the multiplier and the intercept or slope for each tier are divided by 20. For the AESO's preferred Option #1, this yields the investments per year for each rate tier as shown in Table 6.

**Table 6. Investments for each rate tier using Option #1<sup>165</sup>**

Investment	(\$)
Basic	93,150
First 7.5 MW	34,800
Next 9.5 MW	21,350
Next 23 MW	14,650
Remainder	9,300

109. Values of POD charges and investments for each rate tier, analogous to those provided here in tables 5 and 6, are provided in Appendix V for Option #2 and Option #4, as well as for options #4a and #4b.<sup>166</sup> Rate change effects compared to the previous ISO tariff are also shown for each of these options.

#### 4.2.6 Views of ADC, DUC and IPCAA (DUC et al.)

110. DUC et al. raised a number of issues and suggested POD cost function alternatives to the original four considered by the AESO. These alternatives are reviewed below. In some cases,

<sup>164</sup> Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “Coverage Proposed.”

<sup>165</sup> Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “POD Options Summary.” The detailed calculations are shown in the tab labelled “Investment Proposed,” rows 7-11.

<sup>166</sup> Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled “POD Options Summary.”

other interveners or the AESO commented on the positions of DUC et al., in which case their views are also summarized here.

#### 4.2.6.1 AESO's response to previous Commission decisions

111. In argument, DUC et al. stated that the AESO had not complied with (or more specifically, had disregarded) previous Commission directions with respect to POD charges. In particular, DUC et al. argued that the AESO repeated proposals and arguments from the 2013 tariff proceeding even though the Commission rejected these previously. This, they argued, is an abuse of process that imposed additional costs on participants, especially industrial consumers.<sup>167</sup>

112. The major issue that DUC et al. focused on in this aspect of their argument concerns the Commission direction in Decision 2014-242, discussed previously, that the AESO use the full increased capacity made possible by an upgrade project, as opposed to the increase in contract capacity.<sup>168</sup> Due to unanticipated effects that were observed when the AESO attempted to implement this direction, in Decision 3473-D01-2015 (Errata), resulting from the compliance filing to that previous decision, the Commission delayed implementation of that direction “until the matter can be thoroughly explored.”<sup>169</sup> In the view of DUC et al., such a “thorough exploration” would not have included further consideration of Option #1, the AESO's preferred option from the previous tariff proceeding, since that option uses the contract capacity associated with upgrades, and also includes upgrades that involved no increase in capacity. Further, in view of the Commission's previous determinations, according to DUC et al., this option should not have been the AESO's preferred option. As DUC et al. note in reply argument, “... evidence, arguments and directions from 2013 ISO GTA are still valid and ... utilization of DTS contract capacity in the development of the POD cost function continues to be inappropriate.”<sup>170</sup>

113. In argument, the CCA also raised DUC et al.'s concerns about the AESO not complying with Commission directions, which, in part, led to the CCA's recommendation to proceed with Option #4, based on installed rather than contract capacity.<sup>171</sup>

114. In reply argument, the AESO disagreed with DUC et al.'s assertions, stating that “the AESO has not disregarded the Commission's directives from Decision 2014-242,” and that the amended Appendix F documents the AESO's “thorough exploration of the matter of using contract or installed capacity.”<sup>172</sup>

#### 4.2.6.2 Upgrades with no increase in capacity (MW)

115. As noted in the previous discussion of the POD cost function database, there are a number of upgrade projects that involved expenditures but no increase in capacity. In some cases, (some of) these are referred to as the “cooling fan projects.”<sup>173</sup> In their reply argument, DUC et al. argued that both Option #1 (based on contract capacity) and Option #4 (based on installed capacity) that include zero MW upgrade projects are suboptimal.<sup>174</sup> In particular, DUC et al. argued that both these options are inferior to Option #6, which “better reflects cost

<sup>167</sup> Exhibit 22942-X0543, DUC et al., argument, PDF pages 3 and 27.

<sup>168</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 27.

<sup>169</sup> Decision 3473-D01-2015 (Errata), paragraph 31.

<sup>170</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 32.

<sup>171</sup> Exhibit 22942-X0549, CCA argument, paragraphs 42 and 46.

<sup>172</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 95.

<sup>173</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8, footnote 24.

<sup>174</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

causation and the AESO's stated rate design principles."<sup>175</sup> Option #6 is considered below in a subsequent section.

116. As to why upgrade projects involving no capacity increases are suboptimal, DUC et al. refer in their reply argument to an IR response that they provided.<sup>176</sup> This response references a Commission statement in Decision 2014-242:<sup>177</sup>

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

117. The Commission asked DUC et al. to expand on their response in a subsequent IR that provided two scenarios concerning an upgrade that involved two components: (i) a transformer (cost and capacity increase); and (ii) a breaker (cost increase but no capacity increase). In the first scenario, both components are completed at the same time, so the single project involves an increase in both costs and capacity and would be included in the POD database. In the second scenario, component (i) was completed in stage one, but component (ii) was completed in a subsequent second stage, and is considered as a separate project.<sup>178</sup> With this second scenario, both stages could be included as two separate projects in the POD cost database, but the second would involve a zero MW upgrade. Alternatively, as the DUC suggested in its evidence, the second stage could be completely excluded from the database since it does "not reflect the true cost of providing substation capacity."<sup>179</sup> In this context, the DUC expressed the opinion that with this second scenario, both of these options would distort the POD cost function, but there would be a lower level of distortion if the second stage is excluded. No specific reasons for this outcome were provided.

118. In considering the two scenarios advanced in the IR, the DUC developed a third possible way to deal with the second scenario. Their solution, which involved combining the two stages of this scenario into a single project in the POD project database by adding the costs associated with stages one and two together and utilizing the full transformer capacity, forms the basis for Option #6, considered in a separate section below.<sup>180</sup>

119. In its argument, the CCA submitted that the inclusion of zero MW projects "is appropriate as it reflects the natural evolution of a POD over its life."<sup>181</sup>

#### **4.2.6.3 Importance of substation economies of scale**

120. In argument, DUC, et al. emphasized the significant economies of scale present in substation costs. They cite confirmation provided by the Alberta Energy and Utilities Board in Decision 2007-106, which recognized that certain components of POD costs increase at a decreasing rate with the capacity of the interconnection, and concluded on this basis that the

<sup>175</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

<sup>176</sup> Exhibit 22942-X0385, DUC-AUC-2019JAN28-002, PDF page 3.

<sup>177</sup> Decision 2014-242, paragraph 258.

<sup>178</sup> Exhibit 22942-X0385, DUC-AUC-2019JAN28-003, PDF pages 4-9.

<sup>179</sup> Exhibit 22942-X0336, DUC evidence, Q23 PDF pages 15-16.

<sup>180</sup> See Exhibit 22942-X0385, DUC-AUC-2019JAN28-003, PDF pages 4-7 and Exhibit 22942-X0543, DUC et al., argument, PDF pages 29-31.

<sup>181</sup> Exhibit 22942-X0549, CCA argument, paragraph 45.



POD cost function expressed as dollars per MW should be non-linear in shape.<sup>182</sup> According to the DUC witness, Mr. Hildebrand, the economies of scale are more like a factor of four or five than 10 or 20 per cent.<sup>183</sup> In further explanation, he added that a small substation of 5 MW may cost \$1,000,000 per MW, while a big substation of 50 MW may cost only \$200,000 per MW. In other words, there is a five times economies of scale advantage from building an incremental large substation.<sup>184</sup> As support for these statements, the DUC provided an undertaking that referenced and briefly summarized relevant exhibits from the AESO 2006 tariff proceeding that demonstrated the extensive substation economies of scale.<sup>185</sup>

121. In DUC et al.'s view, "the POD cost function should first and foremost reflect the significant economies of scale present in substation costs. This aligns with the AESO's second rate design principle, the 'provision of appropriate price signals that reflect all costs and benefits.'"<sup>186</sup> This objective is consistent with DUC et al.'s Options #5 and #6, which involve higher fixed charges and higher per MW charges at low MW levels and lower per MW charges at higher MW levels than is observed with Options #1, #2 and #4 considered by the AESO.<sup>187</sup> As specified in DUC et al.'s reply argument, "[t]he recommended Option #6 is cost-based and will continue to send the correct price signal that larger substations are more economic and efficient, to those AESO customers who are subject to and can respond to the DTS POD rate price signal."<sup>188</sup>

122. In the hearing, Mr. Martin, for the AESO, stated: "... I would agree that the primary driver of the cost function is to demonstrate a relationship that reflects economies of scale as a service provided through a substation gets larger."<sup>189</sup> In reply argument, while not disputing the importance of substation economies of scale, the AESO argued that DUC et al.'s focus on substation costs that reflect economies of scale is a "flawed objective," as it excludes DFOs that (in the opinion of DUC et al.) do not respond to the price signal. The AESO summarizes its position by stating that "[i]t is incongruous of the ADC-DUC-IPCAA [DUC et al.] to claim that the primary objective of the POD cost function is to recognize economies of scale when the price signal is [in DUC et al.'s opinion] ignored by the DFOs, which represent about 'three quarters or more of the AESO's revenue requirement.'"<sup>190</sup>

#### 4.2.6.4 DFOs respond differently to price incentives

123. The argument that DFOs do not respond to price incentives in the same way as non-DFO customers has been raised in previous ISO tariff proceedings. As the DUC witness Mr. Hildebrand observed in this group's opening statement, "DFOs are not electing DTS contract capacities based on tariff price signals as the Commission correctly concluded in Decision 2014-242."<sup>191</sup> Mr. Hildebrand reiterated this argument in the hearing, stating that DFOs

<sup>182</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 28.

<sup>183</sup> Transcript, Volume 6, page 1008, lines 18-19.

<sup>184</sup> Transcript, Volume 6, page 1009, lines 8-12.

<sup>185</sup> Exhibit 22942-X0524, Mr. Hildebrand undertaking to Ms. Wall.

<sup>186</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 28.

<sup>187</sup> See Exhibit 22942-X0336, DUC evidence, PDF page 20 for a comparison of POD rates for options #1, #2, #4, #4a, #4b and #5. POD rates for Option #6 are provided in Exhibit 22942-X0385, DUC-AUC-2019JAN28-003, PDF page 7. Note that it is not clear, however, if the rates determined by DUC et al. for their options will generate the AESO's POD revenue requirement.

<sup>188</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 7.

<sup>189</sup> Transcript, Volume 4, page 675, lines 8-11.

<sup>190</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 99.

<sup>191</sup> Exhibit 22942-X0518, Mr. Hildebrand opening statement for DUC et al., PDF page 1.

are “simply price takers. They pay the AESO, and then those costs are flowed through to their distribution customers.... In my view, [they] are not responding to that price signal, and they are instead selecting DTS contract capacities based on other factors.”<sup>192</sup> In Mr. Hildebrand’s view, DFOs are indifferent to price signals “[b]ecause it’s a simple pass-through for them. They get a bill from the AESO, and then they just flow it through on their distribution rates, and they even have deferral accounts to reflect the balances. They don’t take any risk. It’s a cost pass-through ... that’s what I mean when [I say] they’re a price taker. They’re not paying those costs; they’re not responsible for those costs; they don’t need to respond to that price signal.”<sup>193</sup>

124. In argument, the CCA speculated that DFOs may not be responding to tariff price signals in a manner similar to non-DFO customers because DFOs make contributions to the TFO for investment in non-standard facilities, which is rate based in the DFO’s books, so that the incentive becomes maximizing the investment in DFO rate base rather than optimizing the contract demand. “In other words, it would appear that DFOs do not respond to tariff price signals based on contract capacity because of misplaced incentives.”<sup>194</sup> However, the CCA views such perverse incentives as “a tariff design anomaly rather than an inherent inability on the part of DFOs to respond to tariff price signals.”<sup>195</sup> In the CCA’s view, the reality of non-price responsiveness of DFO customers must be recognized in POD cost function analysis. The CCA viewed the use of Option #4, which is based on installed rather than contract capacity and includes zero MW upgrade projects, as reflective of this consideration.<sup>196</sup>

125. In response, DUC et al. noted that the CCA’s arguments are similar to those made by the AESO in the 2013 ISO tariff proceeding, which DUC et al. claimed the Commission dismissed. In support, they cited the following from Decision 2014-242:<sup>197</sup>

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

260. The AESO is directed to use the full increased capacity made possible by an upgrade project.

126. The AESO’s position on the issue of DFO price responsiveness in that previous proceeding was summarized by the Commission as follows:<sup>198</sup>

The AESO submitted there was no evidence on the record in this proceeding that the price signals provided by the ISO tariff are not equally effective for both direct connect market participants and DFOs.

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<sup>192</sup> Transcript, Volume 6, page 1008, lines 5-7, and page 1039, lines 13-15.

<sup>193</sup> Transcript, Volume 6, page 1039, lines 17-21 and page 1040, lines 5-8.

<sup>194</sup> Exhibit 22942-X0549, CCA argument, paragraph 43.

<sup>195</sup> Exhibit 22942-X0549, CCA argument, paragraph 44.

<sup>196</sup> Exhibit 22942-X0549, CCA argument, paragraph 46.

<sup>197</sup> Decision 2014-242, paragraphs 259-260.

<sup>198</sup> Decision 2014-242, paragraph 244.

127. In the current proceeding, in Appendix F, in describing the evolution of the POD database since the 2007 tariff application, the AESO described the removal of zero MW upgrade projects as a solution to the DUC's concern about DFOs having different incentives.<sup>199</sup>

In the 2014 ISO tariff compliance filing, an interim methodology to exclude upgrade projects with zero MW contract capacity was proposed by the AESO to address the DUC's concern that DFO's do not have the same incentives as a direct connect customer and these connection projects were moved from the database on an interim basis. This interim methodology was accepted by the Commission in Decision 3473-D01-2015.

128. Later in Appendix F, the AESO described their preference for now using Option #1, based on contract capacity and including zero MW projects, in terms that suggest a degree of uncertainty with respect to DFO price responsiveness.<sup>200</sup>

The AESO has concerns regarding removing projects from the database that do reflect how market participants respond to the price signals of investment and rates. If DFOs are not responding appropriately or are responding differently than direct-connect market participants to the ISO tariff investment and rate price signals, removing DFO data points from the database for this reason will not address the fundamental investment policy issue.

129. Nevertheless, in the hearing, the AESO witnesses confirmed their understanding that market participants in general are all responding to cost signals, but possibly in different or unexpected ways. In response to a question from Commission counsel on whether positive upgrade costs associated with no capacity increase mean that costs depend on something other than capacity, Ms. Papworth, for the AESO, replied:<sup>201</sup>

... we're creating a database that reflects market participants' response to the investment signal. So because these projects are in the past, in the past a market participant responded to the cost signal we were sending through investment in a way that they chose zero megawatts of contract capacity along with the costs.

I agree they're responding to something else in order to incur those costs, but the investment signal we're sending, they responded to, maybe just in a way you would not expect or not in an average manner.

So a market participant that spends dollars with zero megawatt contract capacity is responding to the cost signal. We are capturing that in a database that influences the future cost curve that shows -- that summarize, creates a curve based on past behaviour.

Now a project where a market participant responds with a 2-megawatt contract increase, and let's say the same dollars, it's not zero megawatts, he's responding. But potentially he's not responding in the way on average you would expect him -- expect that market participant to. But they are still responding to the signal.

They're choosing to take the contribution cost, a higher contribution cost on balance for reducing their POD charges over the future.

<sup>199</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 12.

<sup>200</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 24.

<sup>201</sup> Transcript, Volume 4, page 666, line 13 to page 667, line 14.

130. Mr. Martin, also for the AESO, added:<sup>202</sup>

And when we looked at why project cost varied as part of our 2012 contribution policy investigation, we found different reasons for projects varying from what a typical project would be, but we felt that, in all cases, the cost of the project reflected a market participant making decisions that included accounting for the investment available to the market participant.

### Option #6

131. As discussed previously, in response to a Commission IR that introduced different scenarios concerning the inclusion of zero MW upgrade projects, DUC et al. developed an alternative method for dealing with the situation where an upgrade involves components completed at different times, and, in particular, where the second component involves costs but no capacity increase. Subsequently, this method became Option #6, DUC et al.'s recommended POD cost function approach, which, DUC et al. stated in reply argument, the Commission has the evidentiary basis to approve.<sup>203</sup>

132. Option #6 is based on using a database that combines information, where applicable, from the greenfield projects and upgrade projects at the same substation. This results in a dataset with 169 unique substations, with costs and capacities totaled at each substation. As described by DUC et al., the dataset comprises:<sup>204</sup>

- 78 “upgrade substations” where no greenfield project existed; within these upgrade substations, 112 upgrades were undertaken to increase capacity (22 substations had two upgrades each and six substations had three upgrades each);
- 21 “greenfield upgrade substations” where a greenfield project exists; within these, 27 upgrades were undertaken (six substations had two upgrades each);
- An additional six “greenfield upgrade substations,” where upgrades involved no increase in capacity (one substation had two upgrades); and
- 70 “greenfield substations” where a greenfield project exists, and no upgrade occurred.

133. Unfortunately, the data in the DUC's revised Appendix G do not match these described components exactly, instead appearing to contain 77 upgrade substations, 21+6=27 greenfield upgrade substations, and 64 greenfield substations, for a total of 168 observations.<sup>205</sup> Further, the estimated regression using these observations does not match the regression shown in the DUC's IR response, which sets out the same data where they first considered Option #6.<sup>206</sup>

<sup>202</sup> Transcript, Volume 4, page 670, lines 13-25.

<sup>203</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

<sup>204</sup> The dataset for Option #6 is described in Exhibit 22942-X0385, DUC-AUC-2019JAN28-003, PDF pages 4-5 and in Exhibit 22942-X0543, DUC et al., argument, PDF pages 29-30.

<sup>205</sup> The data source, referenced in both cases where DUC et al. describe the data (see footnote 203) are provided in Exhibit 22942-X0386, DUC-AUC-2019JAN28-003 Option 6 DUC Appendix 3 Revised AESO Appendix G POD Cost Function Workbook, in the tab labelled “Combine Greenfield and Upgrade.”

<sup>206</sup> See Exhibit 22942-X0336, DUC-AUC-2019JAN28-003, PDF page 6, and Exhibit 22942-X0386, DUC-AUC-2019JAN28-003 Option 6 DUC Appendix 3 Revised AESO Appendix G POD Cost Function Workbook, in the tab labelled “Combine.”

134. DUC et al. submitted that the sample is both adequately sized and representative, reflecting both greenfield developments and upgrades at greenfield substations. They noted that in the 2007 proceeding, the POD cost function was developed using data from only 28 substations.<sup>207</sup> In their view, it is “better to have fewer and more accurate data points, rather than more data points that have abnormalities,” and that “the POD cost function should represent the inherent economies of scale present in Alberta substations as accurately as possible.”<sup>208</sup>

135. One of the operational details with Option #6 concerns the upgrade substations, where no greenfield project existed. Presumably, in order to have an upgrade, there had to be a substation that could be upgraded, so the key issue is that many details of the substation prior to the upgrade are unknown. As part of the upgrade process, the capacity prior to the upgrade would likely be known, but the original costs of the substation that is upgraded, or even the year those costs were incurred, would generally be unavailable. This is the same problem faced by the AESO with its upgrade projects in its POD cost function estimation – it knows the capacity prior to the upgrade but not the cost of providing that initial capacity. As discussed earlier, the AESO solution is to use estimates from the POD regression that is estimated only using greenfield substations to predict the base costs (those prior to the upgrade) for the sites that are upgraded using their initial capacity, and to add these predicted base costs to the upgrade costs. These new data points, involving the sum of the original and upgrade capacity and the sum of estimated base cost and upgrade cost, are then included in the regression along with the original greenfield data points, and the process is iterated to a solution.

136. The DUC’s solution, although not described in detail, appears to be essentially the same. Specifically, they use the estimates from a regression run on the 91 data points, excluding the upgrade substations, to predict the base costs for these upgrade substations given their pre-upgrade capacity, and these are then added to the upgrade costs. These new data points, involving the sum of the original and upgrade capacity and the sum of estimated base cost and upgrade cost, are then included in the regression along with the original greenfield data points, and the process is iterated to a solution.<sup>209</sup>

137. In argument, although not in the IR where Option #6 was developed, DUC et al. stated:<sup>210</sup>

The Upgrade projects at substations where the underlying base cost is not known and projects where costs are added with no new capacity (the cooling fan projects) should be excluded from the development of the POD cost function. [footnote omitted]

138. This recommendation does not appear elsewhere and is not explained any further. It appears to mean that estimation of the POD cost function with Option #6 would be limited to the 91 data points, excluding the upgrade substations. In this case, possibly the preferred POD regression would be the first regression in the DUC’s solution, described above, that is used to obtain initial estimates of base costs for the upgrade projects, which has an R-squared goodness

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<sup>207</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 30.

<sup>208</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 29.

<sup>209</sup> See Exhibit 22942-X0386, DUC-AUC-2019JAN28-003 Option 6 DUC Appendix 3 Revised AESO Appendix G POD Cost Function Workbook, in the tabs labelled “Greenfield” and “GF+UG Iteration 1” through “GF+UG Iteration 15.” The final data points and estimated regression is included in the tab “Substation Cost Function.”

<sup>210</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 30.

of fit measure of only 0.2232.<sup>211</sup> The DUC also recommended that the pre-AESO projects be excluded; this issue is discussed separately below. There is no documentation that clarifies whether the 168 data points that are used to estimate the POD cost function using Option #6 (or the 91 data points if upgrade projects are excluded) already exclude these pre-AESO projects, although based on substation names in the AESO Appendix G workbook and the DUC's reconfiguration of this workbook, it appears that the 168 data points referred to above do exclude these projects.<sup>212</sup>

139. In rebuttal evidence, the AESO argued that Option #1 better supports its POD objectives, although it commits to conducting further consultation and study concerning the different options and objectives of market participants.<sup>213</sup> In reply argument, the AESO noted that DUC et al.'s recommendation for Option #6 is based on DUC et al.'s objective of reflecting economies of scale in substation costs, which the AESO believes to be flawed, as discussed previously.<sup>214</sup> The AESO also argued that recommendations by market participants concerning modification to elements of the POD cost function are designed to support their own objectives, whereas the AESO is concerned with balancing rate design principles.<sup>215</sup> These concerns pertaining to rate design principles and differing market participant objectives pertaining to the POD cost function specification are discussed further below.

#### 4.2.6.5 Exclusion of pre-AESO projects

140. As discussed above, the DUC also recommended that the pre-AESO projects be excluded from the database used to estimate the POD cost function. This recommendation is incorporated in their options #4b, #5, #6 and #7. In both their evidence and argument, DUC et al. described their IR to the AESO on this matter and the AESO's response:<sup>216</sup>

We note that the average escalation factor for the 18 Pre-AESO projects is 2.279, or the original project costs are increased by an average of 124% to estimate 2018 costs; whereas the Greenfield and Upgrade projects are increased on average 17%. Considering the accuracy of escalation factors up to 32 years please justify the inclusion of the 18 Pre-AESO projects in the POD Project Database.

In response, the AESO provided the same justification for the inclusion of the pre-AESO projects as was provided in the 2013 proceeding.

We submit that the refinements to the POD Project Database precludes the need to continue to use the 18 pre-AESO projects. The size of the POD Project Database is now sufficiently large that pre-1999 projects are no longer required, or appropriate.

<sup>211</sup> Exhibit 22942-X0386, DUC-AUC-2019JAN28-003 Option 6 DUC Appendix 3 Revised AESO Appendix G POD Cost Function Workbook, in the tab labelled "Greenfield."

<sup>212</sup> See the list of included substations for the AESO in Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled "Greenfield," and for DUC et al. in Exhibit 22942-X0386, DUC-AUC-2019JAN28-003 Option 6 DUC Appendix 3 Revised AESO Appendix G POD Cost Function Workbook, in the tab labelled "Combine Greenfield and Upgrade."

<sup>213</sup> Exhibit 22942-X0447, AESO rebuttal evidence, PDF pages 13-14.

<sup>214</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 99.

<sup>215</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 98.

<sup>216</sup> Exhibit 22942-X0336, DUC evidence, Q25, PDF page 17, and Exhibit 22942-X0543, DUC et al., argument, PDF pages 30-31.

When asked “Please explain how the pre-AESO project data can be verified for accuracy, noting the AESO’s application states that the ‘cost and contract information available is very limited’ ”, the AESO responded with:<sup>217</sup>

The AESO cannot verify the values through the cost reports provided to the AESO from the respective transmission facility owners. However, the pre-AESO projects have been included in the POD Project Database in recent filings for the costs to be vetted or assessed.

We note that pre-AESO projects costs could not be vetted in prior proceedings as the AESO does not have, and never did have, costs reports [*sic*] for these projects from the former vertically integrated utilities. Due to the dubious accuracy of the cost data for the pre-AESO Projects, we recommend that it is time the pre-AESO projects be removed from the POD Project Database.

141. In explaining its response in this IR, the AESO reproduced the comments it provided in its 2014 tariff application:<sup>218</sup>

The database used for the development of each of the point of delivery cost functions to date also includes 18 “pre-AESO” load-only projects with in-service dates in 1987-1999. The 18 pre-AESO projects were initially included as the smallest and largest projects in the database to allow development of a more robust cost function, and have been retained for the same reason and to add stability to the cost function through successive tariff applications.

The 18 pre-AESO projects represent about one-fifth of the 87 greenfield projects in the database, which the AESO considers significant. Including those small and large projects provides better representation of the range of points of delivery through which the AESO provides system access service.

The AESO considers that removing those pre-AESO projects would result in underrepresentation of small projects in the database and, by discarding a material sample of stable project data, could potentially result in greater volatility of the cost function through successive tariff applications.

142. The AESO did not comment specifically on this issue further in rebuttal evidence, argument or reply argument, although one of the AESO’s objectives is to maximize the number of projects in the database,<sup>219</sup> which is not achieved if the pre-AESO projects are excluded. Further, the AESO may be opposed to eliminating the pre-AESO projects on the basis of its general argument, described earlier, that recommendations by market participants concerning modification to elements of the POD cost function are designed to support their own objectives.<sup>220</sup> This issue is considered separately, further below.

### Option #7

143. The DUC, in an IR response, also considered a further option for the POD cost function, referred to as Option #7, which uses the same dataset as Option #6, but differs from that option

<sup>217</sup> Exhibit 22942-X0283, AESO-DUC-2018OCT31-002(a), PDF page 4.

<sup>218</sup> Exhibit 22942-X0283, AESO-DUC-2018OCT31-002(a), PDF page 4. The first paragraph of this response is also included in the current AESO tariff application, Exhibit 22942-X0163, Amended application, paragraph 68, PDF page 21.

<sup>219</sup> See Exhibit 22942-X0447, AESO rebuttal evidence, Table 2, PDF pages 11-12.

<sup>220</sup> See Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 36, PDF page 11.

in that the actual investment amount allowed by the AESO is used in place of participant-related costs eligible for investment.<sup>221</sup>

The DUC questions if it would be more appropriate to base the POD cost function on the actual investment amount allowed by the AESO, as this is the amount that would be added to TFO rate bases, which forms the TFO revenue requirements that the AESO recovers in its tariff. It appears that “Participant-Related Costs Eligible for Investment:” includes customer contributions that are not recovered in the AESO tariff.

144. In conducting their empirical analysis and estimation of this option, DUC et al. found that the AESO investment amounts are approximately one-third of the total construction costs. As they noted: “[t]his suggests that for Greenfield and substation upgrades there are large customer contributions, which should not be reflected in the AESO’s tariff.”<sup>222</sup> Their estimated POD cost function based on Option #7 results in a fixed customer charge that is approximately four times as large as the AESO obtained with its Option #1 (\$46,464 versus \$11,480), while POD charges per MW are significantly lower than the AESO’s calculations, further emphasizing the economies of scale for substations.<sup>223</sup> In view of the significant departure this represents from POD charges that have been in place since 2007 and the rate impact this would have on small PODs, DUC et al. submitted that “Option 7 would not be appropriate for the AESO’s 2018 tariff.”<sup>224</sup>

145. As with Option #6, the AESO did not specifically address Option #7 in rebuttal evidence, argument or reply argument.

#### 4.2.6.6 Further consultation

146. As noted previously, in response to the various options that were suggested concerning the POD cost function, the AESO committed in rebuttal evidence, and reiterated in their argument, to further consultation with market participants in the future, but requested that the Commission approve Option #1 in the meantime.<sup>225</sup> In reply argument, DUC et al. submitted that:<sup>226</sup>

The development of the POD cost function and POD rates has undergone extensive stakeholder consultation and the AESO and the end-use ratepayers simply do not agree. We submit that further consultation will not be productive or efficient.

147. The CCA also submitted that, concerning the POD cost function, “further consultation and study is unlikely to produce any incremental benefits from a public interest perspective.”<sup>227</sup> The CCA also recommended that to “ensure consistency, stability and predictability of rates for customers based on reasonable criteria,” whatever POD function is adopted in this proceeding by the Commission, it “be allowed to stand for at least another 5 years prior to the next review.”<sup>228</sup> In contrast, ENMAX argued that “no changes should be made to the POD cost function without

<sup>221</sup> Exhibit 22942-X0336, DUC-AUC-2019JAN28-003, PDF page 7.

<sup>222</sup> Exhibit 22942-X0336, DUC-AUC-2019JAN28-003, PDF page 8 and Exhibit 22942-X0543, DUC et al., argument, PDF page 32.

<sup>223</sup> Exhibit 22942-X0336, DUC-AUC-2019JAN28-003, Table 2, PDF page 9.

<sup>224</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 32.

<sup>225</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraphs 41-42, PDF page 14 and Exhibit 22942-X0558, AESO reply argument, paragraph 134.

<sup>226</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 7 (footnote omitted).

<sup>227</sup> Exhibit 22942-X0549, CCA argument, paragraph 48.

<sup>228</sup> Exhibit 22942-X0549, CCA argument, paragraph 48.



further consultation ...” and that in view of “several outstanding issues that need to be addressed prior to implementing a new POD cost function ... stakeholder consultation is warranted.”<sup>229</sup> In response, DUC et al. noted that “[f]or the 2018 tariff, POD rate issues have been extensively addressed” and again point out that “industrial consumer associations and the CCA agree that further consultation on POD rates will not be productive.”<sup>230</sup>

#### 4.2.6.7 Rate design principles and price signals

148. As discussed previously, DUC et al. believe that “Option #6 better reflects cost causation and the AESO’s stated rate design principles.”<sup>231</sup> In their reply argument, the AESO argued that “... each element of the POD cost function can be modified by a market participant to support its own objectives,” and that “the objective of the rate design that the AESO uses and the investment function, and therefore the underlying POD cost function is to provide a balance of achieving the five rate design principles discussed in the Amended Application.”<sup>232</sup> As summarized in its argument, the AESO “considers that Option #1 would best achieve the objective of allowing the POD cost function to reflect investment decisions of market participants in determining contract capacity in relation to project costs.”<sup>233</sup>

149. In its amended application, the AESO listed the rate design principles as:<sup>234</sup>

- (i) recovery of the total revenue requirement;
- (ii) provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
- (iii) fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- (iv) stability and predictability of rates and revenue; and
- (v) practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.

150. As the AESO described in its application:<sup>235</sup>

The application of these principles to the AESO’s rate design was extensively discussed in both Decision 2005-096 on the 2005-2006 ISO tariff application and in Decision 2007-106 regarding the 2007 ISO tariff application. Those decisions noted the following:

- (a) The first principle would be satisfied by any rate design that, on a forecast basis, recovered the applied-for revenue requirement.
- (b) The second and third principles were considered to be satisfied by rates which recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore is the primary consideration when evaluating a rate design proposal.

<sup>229</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 17.

<sup>230</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

<sup>231</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

<sup>232</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 98 (footnotes omitted).

<sup>233</sup> Exhibit 22942-X0558, AESO argument, paragraph 132 (footnote omitted).

<sup>234</sup> Exhibit 22942-X0163, Amended application, PDF pages 28-29.

<sup>235</sup> Exhibit 22942-X0163, Amended application, PDF page 29.

- (c) The remaining two principles were considered to be given secondary consideration. That is, there should be little need to be concerned about stability and of practicality if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or dramatic changes in cost structure.

Decision 2010-606<sup>[236]</sup> regarding the 2010 ISO tariff application reaffirmed that after the principle of full recovery of the revenue requirement, a rate design reflecting cost causation should generally prevail over other secondary considerations, including rate shock considerations, when assessing the AESO's rate design.

The AESO has accordingly continued to apply in this application the cost causation principles used by the AESO for its rates. In particular, and as discussed above, the AESO has relied on the Transmission System Cost Causation Study and the updated point of delivery cost function to improve the functionalization and classification of costs for the proposed rates.

151. Despite this stated focus of rate design on cost causality, in testimony, Mr. Martin, for the AESO, stated:<sup>237</sup>

The objective of the rate design that the AESO uses and the investment function and, therefore, the underlying POD cost function is to provide a balance of achieving all of those principles.

We recognize, and I think most parties recognize, we cannot achieve all rate design principles simultaneously, and we have to choose a point of balance between them that is a reasonable achievement of those principles.

152. In the context of making improvements to the POD cost function, Mr. Martin added:<sup>238</sup>

And trying to take the precision of that cost function to another level and introducing additional complexity will not, first of all, necessarily help us in achieving any of these principles and, second, may put too much emphasis on one of these rate design principles to the detriment of achieving the others.

We feel we've reached an appropriate balance, and we should be very cautious about simplifying what we've done to say "Isn't in the focus on simplicity too strong" without recognizing that there are other principles we are trying to achieve.

153. However, later he added:<sup>239</sup>

... the AESO is quite open to changing the point-of-delivery cost function as long as there's a valid reason for doing so and it reflects a holistic consideration of all of the impacts and all of the principles we're trying to adhere to. Focusing on the statistical representation of the cost function to a subset of the available data is, I think, too narrow a focus, and we want to just ensure that consideration is comprehensive of all of the things that rely on this point-of-delivery cost function.

154. In terms of price signals, Mr. Martin commented that:<sup>240</sup>

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<sup>236</sup> Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Proceeding 530, Application 1605961-1, December 22, 2010.

<sup>237</sup> Transcript, Volume 4, page 664, lines 4-12.

<sup>238</sup> Transcript, Volume 4, page 664, line 18 to page 665 line 4.

<sup>239</sup> Transcript, Volume 4, page 673, line 17 to page 674 line 1.

<sup>240</sup> Transcript, Volume 4, page 658, line 22 to page 659 line 4.

So we were looking at the whole process as a cohesive whole where one cost function was developed to enable investment and to create a point-of-delivery charge that would keep those components synchronized and provide an appropriate price signal to a market participant that you could either receive investment now or pay higher charges going forward. And maintaining that link was a very important objective.

### Commission findings

155. The Commission did not anticipate that its findings in Decision 3473-D01-2015 (Errata) would result in a recommendation of Option #1, which it rejected in Decision 2014-242. The Commission continues to reject the use of Option #1 for the same reasons explained in Decision 2014-242. This issue is discussed further later in this section.

156. Nonetheless, the Commission considers that the type of analysis conducted by the AESO, as detailed in its amended Appendix F, is consistent with the type of analysis that should be conducted in a thorough investigation. In particular, the lack of further consideration of Option #3, which uses contract capacity for greenfield projects but installed capacity for upgrade projects, which led to the unanticipated effects, and consideration instead of Option #4 that uses installed capacity for both greenfield and upgrade projects, is consistent with the type of analysis the Commission expected.

157. The Commission notes also that the investigation of Option #4 contributed to a number of suggestions regarding the use of installed capacity. In particular, the CCA expressed comfort with Option #4 being used for the POD cost function, although DUC et al. did not, principally because that option continues to include projects that involve zero MW upgrades in installed capacity. This led to DUC et al.'s recommendation to consider further options, in particular Option #4a that excludes projects that involve zero MW upgrades to installed capacity. Additionally, DUC et al. recommended that the AESO consider excluding the pre-AESO projects from Option #4 (resulting in Option #4b), as well as excluding both pre-AESO projects and the projects involving zero MW upgrades to installed capacity (resulting in Option #5). These types of analyses are consistent with what the Commission considers to be a thorough investigation.

158. In response to a Commission IR concerning some of the implications of omitting upgrade projects involving zero MW increases in capacity, DUC et al. produced an alternative approach that involved a fundamental reconsideration of the POD data. Rather than treating greenfield and upgrade projects separately, DUC et al. considered projects on a substation basis, so that various upgrades undertaken at a particular substation are combined with, where available, the greenfield information for that substation. This approach was labelled as Option #6. A related approach, using the same combined substation data, except with the actual investment amount allowed by the AESO rather than participant-related costs eligible for investment, was labelled as Option #7. The Commission sees these approaches as potentially having merit and certainly worthy of further investigation. Unfortunately, arising as they did as outcomes of the IR process, the AESO did not have sufficient opportunity to investigate these options on a basis comparable to the others that it considered. Nonetheless, and in contrast to DUC et al.'s claim concerning their recommended option, the Commission does not consider at this time that it has the "evidentiary basis to approve Option #6."<sup>241</sup>

<sup>241</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

159. In the Commission's view, the AESO is correct to focus on rate design principles when determining rates and investment levels. Nevertheless, in their own words, as discussed earlier, albeit based on a previous Commission decision, the AESO's focus is that "a rate design reflecting cost causation should generally prevail." The Commission considers that modifications to the POD cost function specification or improving the statistical basis for that cost function, does not violate automatically the principles of cost causation.<sup>242</sup>

160. The AESO has emphasized its desire to send what it refers to as the appropriate price signals to market participants, and the Commission expects that the AESO's focus on cost causation in setting rates would generally achieve this objective. However, in the Commission's view, focusing on cost causation means that the POD cost function must provide a sufficiently good representation of what it is designed to demonstrate. For a variety of reasons, as the POD cost function is currently specified and utilized, the Commission does not consider this to be the case. The reasons for this are discussed below.

### Functional form and intercept

161. The estimated POD cost function is a power curve, as described earlier, having the form  $COST_i = \alpha MW_i^\beta$ , where  $\alpha$  and  $\beta$  are parameters that are estimated from the data. Such a specification has no intercept; that is, at a MW value of zero,  $COST_i = 0$ . Yet, as seen in Figure 1, the linearized cost function has a non-zero intercept, at the point labelled "D," with its value determined by extending the slope of the line segment between the estimated value of the POD cost function at 1.5 MW and at 7.5 MW back to the vertical axis (where MW=0). There are at least two problems with this approach.

162. First, it is incompatible with the function that is estimated. Such a function, therefore, cannot be consistent with cost causation. If there are reasons for a non-zero intercept, such as the presence of fixed costs that do not depend on the number of MW, then a different functional form is required. In view of the desire to allow for economies of scale, so that the function has a concave shape, with cost per MW decreasing as the number of MW increases, as the power curve allows, one alternative would be a quadratic specification. This has the form:

$$COST_i = \alpha + \beta MW_i + \gamma (MW_i)^2,$$

where  $\alpha$ ,  $\beta$  and  $\gamma$  are parameters that are estimated from the data. In this case, the parameter  $\alpha$  would be the intercept, that would represent fixed costs. Of course, there are other functional forms that could be considered instead, such as a cubic equation that would be the same as the quadratic but with  $(MW_i)^3$  included as an additional right-hand-side variable, with its own parameter, say  $\delta$ .

163. Second, the way that the intercept is determined, by extending the slope of the line segment between the estimated value of the POD cost function at 1.5 MW and at 7.5 MW back to the vertical axis (where MW=0), from Point "A" to Point "D" in Figure 1, makes the choice of the MW values that define this line segment critical. For example, if the segment was defined as being between 1 MW and 7.5 MW instead of between 1.5 MW and 7.5 MW, this segment would have a different slope, and extending that back to the vertical axis would yield a completely different intercept. Although the MW values defining the line segments were agreed to by the

<sup>242</sup> Transcript, Volume 4, page 664, lines 20-24.

Commission in 2007,<sup>243</sup> it is not clear that these same values should continue to be used some 12 years later. This issue does not appear to have been considered at all in the AESO's latest review.

164. If the form of the cost function that was estimated had been taken into account, so that there was no intercept (i.e., so that  $COST_i = 0$  when  $MW_i = 0$ ), the DTS rates under the AESO's Option #1 would not be extremely different from those shown in Table 5. Specifically, from Table 4, if the intercept had been omitted (Line 6, Column A value of \$11,880.8), costs in the four remaining tiers would total \$73,267.5 (\$85,148.3 less \$11,880.8) instead of \$85,148.3 (Line 6, Column F). As a result, the percentages of these total costs in the four tiers would be modified, as shown in Line 7 of Table 7. This would change the Rate DTS rates as shown in Table 8. Note that even in the absence of an intercept in the POD cost function, there are still fixed monthly charges reflecting non-wires costs. As can be seen from Table 8, compared to the intercept being included, rates in each tier increase by between 15 per cent and 16 per cent, while the customer charge decreases by approximately 93 per cent. This suggests that removing the intercept and redoing the calculations may not lead to rate shock, although this may differ for different options.

**Table 7. Determination of rate tiers for Option #1 with intercept omitted<sup>244</sup>**

Appendix H — 2018 Rate Calculations POD Cost Function and POD Cost Classification						
Line No.	Description	Reference	A	B	C	F
			Customer	Demand		
1	Power Function	As applied for	Costs (\$ million) =	2.7984	x	MW ^ 0.5533
2	Data Points (MW)	2007-106	1.5 MW	7.5 MW	17 MW	40 MW
3	Calculated Values (\$ 000 000)	Lines 1 and 2	\$ 3.502	\$ 8.532	\$ 13.418	\$ 21.543
						\$ 40.071
			Customer	Demand		
			Fixed	≤ (7.5×SF) MW	≤ (17×SF) MW	≤ (40×SF) MW
4	Intercept and Slopes (\$ 000 000)	Lines 2 and 3	\$ 2.245	\$ 0.838	\$ 0.514	\$ 0.353
5	Determinants (cust-months, MW-months)	Table C-10	5,292.1	36,451.3	34,336.1	43,074.6
6	Total Cost Function Costs (\$ 000 000)	Line 4 × Line 5	\$ 30,546.2	\$ 17,648.8	\$ 15,205.3	\$ 9,867.2
7	Cost Classification (%)	Line 6 ÷ Col F	-	41.7%	24.1%	20.8%
						13.5%
						\$ 73,267.5
						100.0%

Note: 1. The "Customer" billing determinant at Line 5 Col A is the sum over all Rate DTS market participants of the substation fraction for each Rate DTS market participant  
2. The "Demand" billing determinants at Line 5 Cols B-E are the sums over all Rate DTS market participants of billing capacity within the bounds indicated as (amounts × substation fraction) for each Rate DTS market participant

**Table 8. POD charges for each rate tier using Option #1 with and without intercept<sup>245</sup>**

Point of delivery charge	With intercept	No intercept	
POD charge – customer × SF	11,480	758.0	/month

<sup>243</sup> Decision 2007-106, Alberta Electric System Operator, 2007 General Tariff Application, PDF page 61.

<sup>244</sup> Source: Table 4, with the intercept value in Line 6, Column A omitted, which causes the total in Line 6, Column F to change, so that the cost classification percentages in Line 7 also change.

<sup>245</sup> Source: Values with the intercept are as calculated by the AESO, as shown in Table 5. Values with no intercept reflect Commission calculations using the revised percentages from Line 7 of Table 7 in the Column labelled "A" in lines labelled 8-12, in Exhibit 22942-X0004.01, Revised Appendix H, Rate Calculations, tab labelled "H-8 DTS Rate."

POD – Demand $\leq (7.5 \times \text{SF})$ MW	4,285	4,957.0	/MW
POD – Demand $> (7.5 \times \text{SF})$ to $\leq (17 \times \text{SF})$ MW	2,628	3,041.0	/MW
POD – Demand $> (17 \times \text{SF})$ to $\leq (40 \times \text{SF})$ MW	1,805	2,088.0	/MW
POD – Demand $> (40 \times \text{SF})$ MW	1,145	1,325.0	/MW

Note: “SF” refers to substation fraction; the charges provided in each line are applied to billing capacity within the bounds defined as amounts multiplied by the substation fraction for each Rate DTS customer.

## Upgrade projects

165. As discussed earlier, one of the major issues with upgrade projects is that the cost of the greenfield project that preceded it is typically unknown. As DUC et al. show, it is possible to match some greenfield projects with upgrades that occurred subsequently, but even in the dataset that they developed for use with their Option #6 and Option #7, for 78 of their 169 data points, the greenfield cost was unknown. Although the upgrade data point, comprising the cost and MW of the upgrade, is a valid data point just like the greenfield data points, there is a reluctance simply to include them in the POD cost regression, apparently due to economies of scale. In other words, the cost of adding a specified number of MW to an existing substation is different from the cost of constructing a new substation with the same number of MW, so including the upgrade points (reflecting upgrade cost and upgrade MW) in the regression along with the greenfield points (reflecting greenfield cost and greenfield MW) would confuse these effects.

166. This led to the iterative approach used by the AESO, where the greenfield cost for upgrade projects is obtained as a prediction from the regression estimated using only the greenfield data points. For each upgrade, the predicted greenfield cost is then added to the cost of the upgrade to yield estimated total cost, and that information, combined with total MW (comprising the sum of greenfield MW and upgrade MW) is included as an additional data point. As Ms. Papworth for the AESO described it, the purpose of this was to “make sure the impact of that upgrade project appeared at the right point on the curve, at the appropriate spot on the curve.”<sup>246</sup> With these new points now included, the regression is then re-estimated, and then using the new estimated regression, revised estimates of the greenfield cost for upgrade projects are obtained. This iterative process is repeated a total of 15 times, until the parameter estimates for two successive iterations are the same.

167. The Commission asked the AESO about any statistical bias involved in such a procedure, but the AESO was unable to answer, although Ms. Papworth, for the AESO, said that she wouldn’t be surprised if told that the results were biased.<sup>247</sup> It is the Commission’s understanding that the problem leading to the bias, in simple terms, is that the upgrade information, which contains no information about the greenfield data, is being used to change the regression line describing the relationship between costs and MW for the greenfield data. The original Greenfield Regression, under certain statistical assumptions, has desirable statistical properties, but these are lost once data points that contain no information about this greenfield regression, are used to change the regression. When asked why the iterative process was adopted, Ms. Papworth responded that “the iterative process was to reduce the impact down to zero of any one project being included in there. ... to create a curve that adding any one of the projects would not

<sup>246</sup> Transcript, Volume 4, page 652, lines 15-18.

<sup>247</sup> Transcript, Volume 4, pages 650-652.

impact the curve additionally. I know that doesn't sound very explanatory, but as the curve is being iterated based on pre-upgrade costs, and you're adding projects, you're fine-tuning it so that no longer estimating the curve provides any impact. ... It doesn't mitigate the statistical concern of basing your pre-upgrade cost on estimation; it's reducing the impact of a pre-upgrade project on the curve, the influence of the project on the curve.”<sup>248</sup>

168. Mr. Martin, also for the AESO, explained that the AESO’s focus in this approach was somewhat related to what they wanted to do with the results. Specifically:<sup>249</sup>

So we were looking at the whole process as a cohesive whole where one cost function was developed to enable investment and to create a point-of-delivery charge that would keep those components synchronized and provide an appropriate price signal to a market participant that you could either receive investment now or pay higher charges going forward. And maintaining that link was a very important objective.

169. The observation that a substation is often upgraded multiple times also apparently played a role in the decision to iterate the regression. As Mr. Martin explained:<sup>250</sup>

So the final -- if we think of a substation that goes through multiple upgrades, the final upgrade data point should not be based on the greenfield version of that substation because it was not an upgrade to the greenfield version of that substation. It was an upgrade to that substation plus multiple upgrades that previously occurred. So if we stopped after the first iteration, we felt it wouldn't be as accurate a representation of the starting point for the third or fourth or final upgrade at the substation as iterating through ...

170. While recognizing that a substation may experience several upgrades, the Commission does not see a link between this observation and the iterative process that is used in the POD cost function estimation. No new information pertinent to the relationship between costs and MW is being added at each iteration; all that changes is the predicted pre-upgrade cost of the substations where upgrades occurred, and these changes result from a change to the relationship between costs and MW for greenfield substations even though the upgrade data points contribute no meaningful information to this relationship. In the Commission’s view, unless conclusive statistical evidence can be provided to show otherwise, the iterative process should not be used; the only valid regression (subject to further comments provided below) is between costs and MW for greenfield substations. To the extent that results based on including the estimated greenfield costs for substations, and iterating, are biased, the results are not meaningful and form no reliable basis for describing cost causation.

171. In the hearing, the Commission discussed an alternative approach concerning upgrade projects with the AESO.<sup>251</sup> This involves estimating a separate regression for the upgrade projects. In view of the evidence suggesting that the costs of an upgrade depend on the MW in place prior to the upgrade, using the power function just for simplicity, a specification that might be considered is:  $COST_i = \alpha MW_i^\beta (StartMW_i)^\gamma$ , where  $StartMW_i$  is the MW in place prior to the upgrade, and  $\alpha, \beta$  and  $\gamma$  are parameters that are estimated from the data. With such a

<sup>248</sup> Transcript, Volume 4, page 654, lines 16-18, and page 655, lines 3-10 and lines 20-24.

<sup>249</sup> Transcript, Volume 4, page 658, line 22 to page 659, line 4.

<sup>250</sup> Transcript, Volume 4, page 660, line 24 to page 661, line 10.

<sup>251</sup> Transcript, Volume 4, pages 657-665.

specification, there would be no need to predict the greenfield cost for upgrade projects, or to iterate to any solution.

172. In response, Mr. Martin was not supportive of this suggestion:<sup>252</sup>

But that would fundamentally change our approach to investment at the end of the day. We would end up having to have two investment functions, one for greenfield projects and one for upgrade projects, and we think that would then lead to two point-of-delivery rates, one for initial greenfield cost at a substation, and one for upgrade cost at a substation.

173. The Commission observes that this response is not quite accurate, however, since the three variables in the suggested regression specification are known for all projects, where  $StartMW_i = 0$  for all greenfield projects. Hence, this regression specification could be estimated in one pass, using all the data, greenfield and upgrades, with no need to estimate separate regressions for the two groups of projects. In any event, the need to potentially use more than one regression does not appear to be the main thrust of Mr. Martin's lack of support for this alternative specification. In further testimony he added:<sup>253</sup>

But I will repeat what I said a little while ago, which is that we began with an end in mind. We were wanting to develop a function that would provide a basis upon which we could develop an investment approach and a point-of-delivery charge that would be robust and sustainable going forward.

Creating a curve that has multiple explanatory variables suggests those explanatory variables will be used in determining the investment level and the charges to market participants, and especially on the rate DTS charges side.

Embedding an additional variable such as the beginning megawatts at the substation before the upgrade project, would create significant complexity in managing point-of-delivery charges going forward. And unless we make a decision to break the link between the point-of-delivery charges and the investment level, we don't think it's appropriate to introduce variables that will be impractical and difficult to administer in the rate going forward.

174. Mr. Martin continued his answer by discussing rate design principles and how improving the precision of the POD cost function by adding complexity "will not, first of all, necessarily help us in achieving any of these principles and, second, may put too much emphasis on one of these rate design principles to the detriment of achieving the others."<sup>254</sup> As stated previously, in the Commission's view, the AESO's focus in rate design is on cost causation, and if the POD cost function is misspecified, then it offers no support for cost causation. Nevertheless, taken together, Mr. Martin's responses help to identify the crux of the matter. In a question to Mr. Martin, when Commission counsel suggested that the POD cost function was required to do "heavy lifting," in terms of the various roles it is meant to play, including showing a relationship between costs and megawatts, sending a price signal, and reflecting past decisions, Mr. Martin declined to characterize it this way, stating instead that its main focus was "to demonstrate a relationship that reflects economies of scale as a service provided through a substation gets larger."<sup>255</sup> In the Commission's view, if this was the primary objective, the AESO's focus would

<sup>252</sup> Transcript, Volume 4, page 658, lines 6-13.

<sup>253</sup> Transcript, Volume 4, page 662, line 15 to page 663, line 10.

<sup>254</sup> Transcript, Volume 4, page 664, lines 20-24.

<sup>255</sup> Transcript, Volume 4, page 674, lines 2 to page 675, line 11.



be on specifying the POD cost function correctly, as it is only in this way that it can reliably demonstrate characteristics such as economies of scale. Once this is done, policy issues, such as sending the “right” price signals can then be addressed. This issue is considered further below.

### **Additional explanatory variables in the POD cost function**

175. The issue of whether there are other explanatory variables that should be included in the POD cost function specification arises in the context of the zero MW upgrade projects, discussed earlier. These projects involve positive costs, but no change in capacity (MW). The Commission asked the AESO in an IR whether this was proof that costs depend on more than just MW, but the AESO responded that it did not. When this issue was pursued in the hearing, Ms. Papworth for the AESO agreed that market participants “are responding to something else in order to incur those costs,” but stated that the AESO “is creating a database that reflects market participants’ response to the investment signal.”<sup>256</sup>

176. This misunderstanding appears to the Commission to stem from the same issue discussed earlier, namely the use of the POD cost function to represent the determinants of costs and to send price signals. Focusing on the first issue, the answer is clear to the Commission. POD costs clearly depend on something in addition to MW. If this was not the case, costs could not be incurred without MW increasing. With respect to the second issue, it appears that the AESO wants to send price signals that only depend on MW. It is not clear to the Commission why either of these objectives precludes the other.

177. With respect to other explanatory variables, Mr. Martin explained that one of the main reasons for spending without increasing MW is to improve reliability.<sup>257</sup> He conjectured that a reliability variable might be represented by some kind of redundancy factor, but that “it would be difficult to assess on a historical basis for existing substations, might be possible going forward.”<sup>258</sup> Again he suspected that adding such a variable would add an additional level of complexity without perhaps adding a lot to the POD cost function. However, in the Commission’s view, this latter comment is incorrect. If there are other factors besides MW that affect costs, and they are omitted from the POD cost function specification, that equation will suffer from omitted variable bias. As a result, the estimates obtained will be unreliable, and will not provide information about cost causation that can be used in setting rates. Since cost causation is the focus in rate setting, it is imperative that the POD cost function, which provides that information, be specified as well as possible.

### **Omitting data points**

178. One of the AESO’s criteria that it used to rank different options concerning the POD cost function specification is that the number of projects in the database be maximized.<sup>259</sup> Based on this criterion, excluding zero MW upgrade projects or excluding pre-AESO projects, or both, as in DUC et al.’s options #4a, #4b or #5, or considering a database in which all projects at a particular substation are treated as a single observation for that substation, as in DUC et al.’s Option #6 and Option #7, receive a lower ranking.

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<sup>256</sup> Transcript, Volume 4, page 666, lines 12-24.

<sup>257</sup> Transcript, Volume 4, page 669, lines 8-10.

<sup>258</sup> Transcript, Volume 4, page 669, line 23 to page 670, line 10.

<sup>259</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 12.

179. The AESO argued that “removing projects from the database must be based on clear defensible reasons of why those project data points do not reflect any future expected behavior of market participants making investment decisions.”<sup>260</sup> In contrast, DUC et al. argued that “[i]n the development of the POD cost function, it would be better to have fewer and more accurate data points, rather than more data points that have abnormalities.”<sup>261</sup> In the Commission’s view, while there should be clear defensible reasons for excluding projects, when focusing on estimation of the POD cost function, these reasons need not be related to reflecting future expected behaviour of market participants. It appears to the Commission that the AESO’s focus on its stated criterion here is aimed at price signals rather than the POD cost function itself. As noted earlier, it is the Commission’s view that if the POD cost function is misspecified, then any price signals that are derived from the estimated POD cost function are likely to be misleading.

180. The issue of zero MW upgrade projects was discussed in the previous ISO tariff decision, and the Commission continues to hold the same view concerning this issue that it expounded in that decision. The AESO appears to regard the exclusion of upgrade projects with zero MW contract capacity, which it proposed “to address the DUC’s concern that DFO’s [*sic*] do not have the same incentives as a direct connect customer” as an interim methodology,<sup>262</sup> that it apparently no longer needs to consider. However, none of the reasons that led to the use of that interim methodology have changed. If costs are specified as depending only on MW, as in the AESO’s current POD cost function specification, in the Commission’s view, upgrade costs that are not associated with a change in capacity (MW) cannot be included. Of course, if, as discussed earlier, the POD cost function specification is changed to include additional explanatory variables, and, in particular, an intercept, then there may be a role for zero MW upgrade projects to play in the estimation. Until that time, the Commission’s view is that zero MW upgrade projects should continue to be excluded. For clarity, this finding would also apply to zero MW upgrades in contract capacity if contract capacity is the only explanatory variable in the POD cost function, as in Option #4. Thus, the Commission prefers Option #4a to Option #4.

181. DUC et al. also raised the issue of excluding the pre-AESO projects. As discussed earlier, the AESO did not provide any considered reasoning concerning these projects, other than to restate its prior position. In particular, the AESO did not provide any arguments to counter those of DUC et al. that these projects should be excluded, (i) because the costs they are based on are of dubious accuracy and have never been thoroughly vetted; and (ii) because the pre-AESO projects were escalated by an average of 124 per cent to estimate 2018 costs (and escalation factors over a 32-year period may not be reliable), whereas the greenfield and upgrade projects were increased on average 17 per cent. In the Commission’s view, this is convincing evidence to consider excluding these projects from the POD cost function estimation. However, before deciding this outcome, analysis of the coverage of the current version of the database with and without these observations included, to assess the extent of any contribution they make or that is otherwise missing, is needed.

182. With respect to DUC et al.’s Option #6 and Option #7 that are based on treating all greenfield and upgrade projects at a particular substation as a single observation for that substation, thereby severely reducing the number of data points used in the POD cost function estimation, the AESO did not appear to have a specific view of that dataset. Of course, this

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<sup>260</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 12.

<sup>261</sup> Exhibit 22942-X0543, DUC et al., argument, PDF page 29.

<sup>262</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 12.

situation is somewhat different, in that upgrades are not being omitted (except, potentially, for zero MW upgrades), but are incorporated into the data for the substation to which they pertain. In the hearing, Mr. Martin, for the AESO, stated that:<sup>263</sup>

When a market participant system access service request results in an upgrade to a substation, we treat that upgrade as a standalone cost. And we want investment that corresponds to that standalone cost. ... So we don't go back and say, well, let's look at the total cost that was ever constructed at that substation, revisit prior contribution decisions for the initial construction and treat it as a combined project. We treat the increment as a single project, and that's the way we felt the upgrade project should be looked at in the development of the cost curve itself.

183. This response does not indicate that assembling the data in the way that DUC et al. proposed for their Options #6 and #7 is not a reasonable way to proceed; rather it indicates that it may not result in the investment determination that the AESO wants for the upgrade. It appears to the Commission that organization of the data in the way proposed by DUC et al. may be beneficial, particularly in the way that, in principle, it avoids the need to predict the greenfield cost for an upgrade project. Of course, as discussed earlier, in practice there are many upgrade projects that could not be matched with a greenfield project, which mitigates this advantage. In any event, the Commission considers this to be an approach that merits further investigation.

184. Finally, in discussing the use of a reliability variable in the POD cost function, Mr. Martin considered the question of whether projects where such a variable could not be constructed should be excluded from the dataset.<sup>264</sup> His response was that “the cost of the project reflected a market participant making decisions that included accounting for the investment available to the market participant,” and the AESO “couldn’t find a basis for developing thresholds for excluding projects.”<sup>265</sup> Specifically, he went on to suggest that any chosen threshold could lead to changed behaviour by market participants.<sup>266</sup> In the Commission’s view, this response is confusing the POD cost function, designed to show the relationship between POD costs and whatever variables cause those costs to be incurred, and the investment function and price signals that the AESO wishes to send to market participants. The Commission recommends an approach that separates these two issues in order to avoid, or at least reduce the scope of, the concern of the AESO that different market participants have different objectives for the POD cost function, where “[s]ome may advocate for a perfect statistical relationship, whereas other market participants may want the POD cost function to drive the maximum amount of investment.”<sup>267</sup>

### **Installed versus contract capacity**

185. The Commission considers that it has made its view on this issue clear in past decisions, but for clarity, since costs that are incurred in constructing greenfield PODs depend on installed capacity, installed rather than contract capacity is the relevant explanatory variable to include in the POD cost function, alongside other possible explanatory variables as discussed above. However, for upgrade projects, in some cases there is an increase in contract capacity but not in

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<sup>263</sup> Transcript, Volume 4, page 656, line 23 to page 657, line 1, and page 657, lines 7-14.

<sup>264</sup> Transcript, Volume 4, page 670, lines 16-18.

<sup>265</sup> Transcript, Volume 4, page 670 lines 23-25, and page 671, lines 1-2.

<sup>266</sup> Transcript, Volume 4, pages 671-674.

<sup>267</sup> Exhibit 22942-X0447, AESO rebuttal evidence, PDF page 12.

installed capacity,<sup>268</sup> which indicates that for these projects it may be necessary to consider both contract and installed capacity as explanatory variables, notwithstanding potential issues of multicollinearity as the AESO noted in an IR response.<sup>269</sup> In the Commission's view, this is another reason why it may be necessary to treat greenfield and upgrade projects differently in POD cost function estimation.

186. When the AESO attempted to use installed capacity previously in response to the Commission directions in Decision 2014-242, this led to unintended consequences, as discussed previously. Based on the discussion of this issue in the amended Appendix F of the current application, the Commission understands that these issues are resolved to a great extent when installed capacity is used for both greenfield and upgrade projects (as in Option #4), rather than just for upgrade projects (as in Option #3).

187. Despite this apparent resolution of the unintended consequences when using installed capacity, the AESO continues to prefer Option #1, where contract capacity is used for all projects. As the CCA noted in its argument, the AESO's preference for Option #1 remains despite Option #4 having "the best ranking in relation to provision of appropriate price signals" and reflecting "the best R-squared statistical confidence of the regression analysis among the four options considered by the AESO."<sup>270</sup>

188. With respect to the AESO's evaluation of options in its rebuttal evidence, the only evaluation criteria where Option #4 is not the best, or equal best, is in terms of "lumpiness of installed capacity" and "number of assumptions."<sup>271</sup> As explained in amended Appendix F, the former is potentially an issue with the ability of investment levels to provide price signals, rather than with the POD cost function specification.<sup>272</sup> The second relates to the determination of installed capacity – which the AESO has taken to be transformation capacity – which may be limited by such factors as the number of breakers and cooling fans.<sup>273</sup>

189. An additional issue, not included in the evaluation criteria, although it also pertains to assumptions, concerns the conversion or "translation" of a POD relationship based on installed capacity to one based on contract capacity, once the POD cost function has been estimated. As the AESO explained in amended Appendix F, such translation is necessary "to maintain alignment between rates and investment. In other words, ensure that rates are based on contract capacity and that investment could be determined based on contract capacity."<sup>274</sup> The AESO's solution, in amended Appendix F, is, subsequent to estimation, to divide installed capacity values

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<sup>268</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled "Contract vs Installed," column "I."

<sup>269</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-049(f), PDF page 120.

<sup>270</sup> Exhibit 22942-X0549, CCA argument, paragraph 46. The Commission notes that comparing R-squared values among specifications that are not all estimated using the same set of data points is not a reliable method for selecting the preferred specification.

<sup>271</sup> Exhibit 22942-X0447, AESO rebuttal evidence, Table 2, PDF pages 11-12.

<sup>272</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 13.

<sup>273</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF pages 13-14.

<sup>274</sup> Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF page 19.

by the average ratio of installed to contract capacity over all PODs, or 2.9949.<sup>275</sup> In other words, if the estimated POD cost function for Option #4 based on installed capacity has the form:<sup>276</sup>

$$COST_i = 1.1334 IMW_i^{0.6607},$$

where  $IMW_i$  is installed capacity in MW, the translated function is:

$$COST_i = 1.1334 (CMW_i \times 2.9949)^{0.6607},$$

where  $CMW_i$  is contract capacity. Rearranging, this translated function can be written as:

$$COST_i = 1.1334 \times (2.9949)^{0.6607} CMW_i^{0.6607}, \text{ or}$$

$$COST_i = 2.3395 CMW_i^{0.6607}.$$

Once in this form, the determination of POD rates proceeds as explained previously, using the same rate tiers and, since the contract MW values that define the limits of each tier have not changed, the same values of billing determinants within each tier.<sup>277</sup>

190. As can be seen from a comparison with the POD cost function for Option #1, stated earlier but reproduced here for convenience,  $COST_i = 2.7984 MW_i^{0.5533}$ , the POD cost function for Option #4 has different estimated parameters but is essentially a scaled version of the same function as in Option #1. In the Commission's view, this does not adequately capture the effects of using installed rather than contract capacity. For clarity, the issue here is not with the estimated Option #4 POD cost function, but with the mechanism used to convert it to one that is written in terms of contract capacity.

191. In their response to a Commission IR concerning the relationship between installed and contract capacity, the AESO provided graphs of the ratio of installed to contract capacity against either installed or contract capacity.<sup>278</sup> As Ms. Papworth for the AESO confirmed, these show a large variation in the ratio, from zero to approximately 80.<sup>279</sup> In view of this large variation, the AESO was asked in an IR about the merits of the adjustment, as just described, to move from installed capacity to contract capacity. In their response they noted that "the methodology the AESO used in the analysis for Option 4 is simple and incorporates all project data, reflecting all market participant decisions regarding contract capacity, installed capacity and project costs."<sup>280</sup> In Ms. Papworth's view, "this was the one method that we looked at that could be easy to replicate, easy to understand. ... the other option would be to be billing our POD charges based

<sup>275</sup> See Exhibit 22942-X0027.02, Revised Appendix F – POD Cost Function Report, PDF pages 19-21. This revised value is taken from Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled "Contract vs Installed," cell L10.

<sup>276</sup> Revised numbers are taken from Exhibit 22942-X0018.03, Revised Appendix V – Updated Options for POD Cost Function, tab labelled "Option 4 V-6."

<sup>277</sup> Rather than use this last function with the original rate tiers, the AESO uses an equivalent procedure that utilizes the estimated function based on installed capacity but with each of the MW values that define each rate tier (as in Line 2 of Table 4) multiplied by 2.9949. Either procedure results in the same POD rates for each tier and the same fixed charge.

<sup>278</sup> Exhibit 22942-X0268, AESO-AUC-2018NOV01-049(j) and (k) Attachment.

<sup>279</sup> Transcript, Volume 4, page 679, lines 2-6.

<sup>280</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-049(l), PDF page 121.

on installed capacity, which seemed to be a major shift, a major structural change in investment and rates.”<sup>281</sup>

192. Examining the actual ratios for each POD, it is apparent that for almost one half of the upgrade projects, the ratio of installed capacity to contract capacity is zero, reflecting an increase in contract capacity that required no increase in installed capacity.<sup>282</sup> In this case, averaging the ratio over all projects does not appear to be representative of the relationship between installed and contract capacity. However, in the Commission’s view, billing POD charges based on installed capacity, when not all market participants are necessarily involved in the decision concerning installed capacity, which Ms. Papworth considered to be the other option, is also not reflective of cost causation.

193. With respect to the POD rates, given the AESO’s revenue requirement and the share of this allocated to PODs, the key determining factor, as explained earlier, is the percentage of the POD revenue requirement allocated to each rate tier. For Option #1, as shown in Table 4, this is determined by multiplying the slope of the POD cost function in each tier (and value of the intercept) by the billing determinants for that tier (or for the intercept) to obtain the costs for each tier, and then evaluating the share of total costs over all tiers that lies within each tier.

194. In its application, the AESO does not explain how billing determinants are determined for each tier, limiting its description to the comment that “Billing determinants are calculated using historical and year-to-date ratios between DTS Energy and each individual billing determinant ...,”<sup>283</sup> and referring to Table H-12 of Appendix H to the application. In notes to that referenced table, DTS Billing Capacity within each tier is defined as “the sum over all Rate DTS market participants of the Rate DTS billing capacity within the bounds defined as amounts multiplied by the substation fraction for each Rate DTS market participant,” while billing determinants associated with the intercept, referred to as “DTS Market Participants (Equivalent)” are defined as “the sum over all Rate DTS market participants of the substation fraction for each Rate DTS market participant.”<sup>284</sup>

195. Based on these descriptions, the Commission is unable to determine whether, even using the current contract-capacity based analysis, billing determinants, presumably based on various forecasts, are calculated for each POD and then allocated accordingly to tiers. Supposing that to be the case, or assuming that it could be done, since the installed capacity is known for each POD, these billing determinants for each POD could, in principle, be allocated to tiers based on installed capacity rather than contract capacity. In other words, if a particular POD has contract capacity of 5 MW, but install capacity of 10 MW, the billing determinants for that POD would be allocated to the tier that includes 10 MW rather than the tier that includes 5 MW.<sup>285</sup> Once this has been done for all PODs, using similar procedures as for Option #1, costs for each tier (and the intercept) and subsequently the share of costs in each tier, could then be determined. With

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<sup>281</sup> Transcript, Volume 4, page 679, lines 10-17.

<sup>282</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook, tab labelled “Contract vs Installed,” column “I.”

<sup>283</sup> Exhibit 22942-X0163, Amended application, PDF page 32.

<sup>284</sup> Exhibit 22942-X0004.01, Revised Appendix H – 2018 Rate Calculations, tab labelled “H-12 Determinants”.

<sup>285</sup> Of course, this would presuppose some pre-determination of the installed MW values that would define each rate tier based on installed capacity, an issue that to date has apparently not been considered.

this type of approach, costs are based on the POD cost function that is based on installed capacity, but POD charges would be based on the contract capacities.

196. There are potentially a number of difficulties associated with implementation of the scheme described here, including the need to determine billing determinants for each POD, but one of the most problematical would be that two different market participants with the same MW contract usage would be charged different POD rates if the installed capacities of the PODs with which they are associated fall in a different tiers. To the extent that they did not choose the installed capacity, this would not appear to be consistent with rate design objective (iii), defined earlier, namely “fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies.” This also raises a more general issue, discussed below.

197. As a potential approach to resolve at least some of the issues raised here, one possibility may be to maintain the same type of approach that the AESO currently uses to convert installed capacity to contract capacity, but rather than using a constant ratio of installed to contract capacity for all PODs, the AESO could consider using several different ratios to do the conversion, depending on certain characteristics of the POD being considered, potentially including its capacity. In the Commission’s view, this type of approach (or other alternatives that might be considered) requires considerable analysis before it could be implemented. For this reason, until such analysis is conducted, which the Commission would expect prior to the next ISO tariff application, the Commission is reluctant to embrace a POD cost function methodology that uses installed capacity.

### **Relevant costs and price signals**

198. The more general issue referred to above concerns why POD charges are related to the cost of constructing PODs, a question which is related to the alternative cost data that DUC et al. consider in their Option #7. As noted earlier, among potential other factors, POD costs reflect installed capacities, at least for greenfield projects, although for upgrade projects they may reflect either or both of contract and installed capacity increases. At the time the POD is constructed, costs comprise contributions and AESO investment. Unfortunately, the share of each of these two components is somewhat flexible, changing each time the POD cost function is estimated, since investment amounts are based on the estimated POD cost for the specified number of MW, as explained previously. Nevertheless, at some point a POD has been constructed for a certain cost, and funded through these two sources, contributions and investment. This raises the question of why the annual revenue requirement that the AESO has allocated to PODs is to be collected based on rates that are set from estimation of a POD cost function that comprises a relationship between one or potentially more explanatory variables and these total costs.

199. The Commission understands that this question may have been addressed in the past, but with a view to undertaking a comprehensive analysis of the POD cost function specification, including the various options raised by DUC et al., the Commission considers it would be helpful if the AESO clarified why POD construction costs play a role in determining POD rates, any alternatives that may be available, and the effects and implications of the changes that occur in investment levels every time the POD cost function is re-estimated.

200. On the issue of investment levels and the price signals that they encompass, the Commission is mindful of the AESO’s objective of sending price signals to market participants that will facilitate efficient decision making. However, as emphasized throughout this section,

the Commission's view is that a necessary precondition for providing price signals that reflect cost causation is that the underlying POD cost function be specified as well as possible. As discussed here, this may mean, among other things, including additional variables, or estimating separately for greenfield and upgrade projects. Any of these types of changes has the potential to complicate the derivation of POD rate charges and investment levels, but the Commission expects that the outcome will be that the determination of these components will be better understood and less subject to criticism.

## Summary

201. In view of the difficulties identified with many of the options, including Option #4a which, if not for issues with the conversion from installed capacity to contract capacity, would otherwise be the Commission's preferred option, at least on an interim basis, the Commission has decided that the AESO should continue with the status quo, as reflected in Option #2, based on contract capacity but excluding the zero MW upgrade projects.

202. The Commission directs the AESO to conduct a thorough investigation of alternative approaches using installed capacity, although contract capacity also may play a role for upgrade projects. This should, at a minimum, comprise the following:

- (1) No further consideration of using contract capacity as the explanatory variable for the POD costs associated with greenfield projects;
- (2) Investigation of separate POD regressions for greenfield and upgrade projects, or for a single regression that incorporates different explanatory variables for the two types; for example, by including previous MW as an explanatory variable, where previous MW would equal zero for greenfield projects, or by utilizing various qualitative (dummy) variables that are equal to one for upgrade projects but equal to zero for greenfield projects (or vice-versa), included in the regression either or both additively and multiplicatively;
- (3) No further consideration of including zero MW upgrade projects in the analysis unless and until the specification is modified to allow costs to depend on some relevant explanatory variable in addition to MW, or possibly an intercept;
- (4) Investigation of the use of an alternative functional form that allows for the possibility of an intercept; if such an alternative does not prove to be useful, dropping the fiction of an intercept for a power function that does not have one;
- (5) Investigation of a specification that, like Option #6, uses a data set where all the projects for a particular substation are considered together;
- (6) Evaluation criteria for different POD cost function specifications that do not focus on the price signals that are sent, but rather focus on the specification itself; as emphasized throughout the preceding Commission findings, no useful information about cost causation can flow from an incorrect POD cost function specification;
- (7) No further consideration of the iterative process concerning upgrade projects for which the greenfield costs are unknown; as explained above, this process modifies the relationship between known costs and MW for greenfield projects without having any information that can contribute to this relationship;



- (8) Using criteria to evaluate alternative specifications or approaches that recognize that specifications with different datasets cannot be compared on the basis of R-squared, and where omission or inclusion of data points is based on defensible criteria concerning the function specification rather than the price signals that are sent or objectives concerning recognizing participant behaviour;
- (9) Notwithstanding the AESO's stated objective to maximize the number of projects in the database, evaluation of the value of continuing to include the pre-AESO projects, considering their age and the extent of inflation adjustments that they require, in terms of their contribution to the range of projects included in the analysis and the empirical implications of their inclusion or omission; and
- (10) Consideration of alternative methods that can be used to convert information from a POD cost function estimated using installed capacity to one where rates are based on contract capacity, in such a way that this conversion or translation does not involve adjustment by a constant ratio and results in a function that is not just a scaling of the Option #1 results.

203. In view of the comments by several parties on the non-productive nature of the type of consultations that have been used in the past concerning the POD cost function specification, the Commission expects that any future consultations concerning the POD cost function issues identified above, as well as any others that may arise concerning the POD cost function specification and analysis, be conducted in a manner that is conducive to obtaining meaningful input from those consulted, including providing them with the relevant data sets in a timely fashion to allow them to conduct their own analysis. While ranking of alternative criteria by those being consulted, and statements concerning their degree of satisfaction with those criteria, can provide useful information in some cases, the Commission does not find that this should be the major focus of any consultation.

204. The Commission recognizes that its recommendations that focus on the POD cost function specification itself rather than the price signals that it sends, and the potential decoupling of these two components, necessarily means that the AESO must reconsider how the results of the POD cost function estimation, reflecting cost causation, can reasonably inform their decisions concerning POD rates and investment levels. The Commission expects this process to be transparent, and to include an explanation of, among other things:

- (1) how billing determinants are allocated to tiers;
- (2) how such allocations would change if the tiers change;
- (3) how and why POD construction costs play a role in determining POD rates;
- (4) any alternatives that may be available to basing POD charges on POD construction costs, including possibly focusing on a component of these costs, and the advantages and drawbacks of any such alternatives;
- (5) the effects and implications of the changes that occur in investment levels every time the POD cost function is re-estimated;
- (6) the purpose of recalculating investment levels for existing PODs; and

- (7) the possibility of basing future investment level determinations separately for upgrades and greenfield projects, and possibly conditional on existing capacity to reflect and encourage efficiencies (economies of scale).

### 4.3 Classification of other costs

205. The AESO stated the following in its 2018 ISO tariff application regarding the classification of other costs:

The remainder of the AESO's revenue requirement comprises of costs related to ancillary services, transmission line losses and the AESO's own administration. The classification of those costs is proposed to remain as approved in Order U2008-217 for the 2007 ISO tariff, and is provided in Table H-5 in Appendix H to this application.<sup>286</sup>

### Commission findings

206. Parties did not bring forward any issues regarding the classification of other costs. The Commission has reviewed Section 4.4 of the 2018 ISO tariff application and Table H-5 in Appendix H.<sup>287</sup> The classifications in Table H-5 appear reasonable and are consistent with those approved in Order U2008-217.<sup>288</sup> Therefore, the Commission approves the AESO's classification of other costs as filed.

## 5 Rate DTS

207. The AESO determines its charge under Rate DTS in a settlement period as the sum of the connection charge, the operating reserve charge, the transmission constraint rebalancing charge, the voltage control charge and the other system support services charge. The AESO determines its connection charge as the sum of bulk, regional and point of delivery charges times the applicable volume for each component.

### 5.1 Rate DTS: Bulk and regional system costs

208. The AESO did not propose any changes to the bulk and regional tariff design in this proceeding. In a letter dated April 30, 2018, the AESO proposed that the bulk (12 CP methodology) and regional tariff rate design should be analyzed in a consultation process outside of Proceeding 22942. The AESO requested the Commission to direct that the issue of whether the applied for bulk and regional tariff design should be changed will not be considered in this proceeding.<sup>289</sup> In a ruling dated June 29, 2018, the Commission ruled that Proceeding 22942 would not include an examination of the bulk and regional tariff rate design that had been approved in Decision 2014-242.<sup>290</sup>

<sup>286</sup> Exhibit 22942-X0002.01, 2018 ISO Tariff Application, paragraph 78.

<sup>287</sup> Exhibit 22942-X0004.01, Revised Appendix H, Spreadsheet H-5 DTS Classification.

<sup>288</sup> Order U2008-217, Compliance Filing – Electric Rates, Alberta Electric System Operator (AESO) 2007 GTA Second Refiling, Application 1572160-1, June 25, 2008.

<sup>289</sup> Exhibit 22942-X0129, paragraph 3.

<sup>290</sup> Exhibit 22942-X0156, paragraph 33.

## Commission findings

209. The Commission ruled that the AESO should examine its 12 CP methodology in its next comprehensive tariff application.

### 5.2 Rate DTS: Power factor deficiency charge

210. The AESO submitted that the transmission system must be capable of serving both the real (MW) and reactive (MVA) power needs of market participants. Rate DTS recovers the costs of the transmission system primarily on a real power (MW) basis, including facilities sufficient to serve reasonable reactive power needs. In the case of the ISO tariff, as well as the tariffs of most DFOs, reasonable reactive power needs are those that result in a power factor of 90 per cent or higher. Costs of serving reactive power needs that arise from power factors of less than 90 per cent are recovered through the power factor deficiency charge.<sup>291</sup>

211. The power factor deficiency charge provides an incentive for load market participants to manage their reactive power requirements so that their power factor is at least 90 per cent at the point of delivery. The 90 per cent threshold aligns with similar thresholds in the tariffs of most DFOs. The 90 per cent threshold has been in ISO tariffs charged for system access service to loads since the restructuring of the electric industry in Alberta in 1996.<sup>292</sup>

212. The current subsection 7(b) of Rate DTS includes a power factor deficiency charge as follows:<sup>293</sup>

Other System Support Services Charge

**7** The **ISO** must determine the other system support services charge as the sum of:

**(a) the highest metered demand in the settlement period multiplied by \$46.00/MW/month; and**

**(b) when power factor is less than 90% during the interval of highest metered demand in the settlement period, \$400.00/MVA multiplied by the apparent power difference calculated during the interval of highest metered demand in the settlement period as the difference between the metered apparent power and 111% of metered demand.**

213. In its application, the AESO proposed the following three changes to the power factor deficiency charge:

- (i) To no longer waive power factor deficiency charges at load sites with downstream generation, whether for a DFO or a direct-connected end-use consumer effective as of December 31, 2016. Sites that already have a waiver would continue to have a waiver.
- (ii) To increase the power factor deficiency charge to \$1,200 per MVA of apparent power difference, from its current level of \$400.00 per MVA.
- (iii) To index the power factor deficiency charge to the weighted average increase in transmission system costs in future ISO tariff applications and ISO tariff updates.

214. Accordingly, the AESO proposed that subsection 7(b) of Rate DTS be revised as follows:

<sup>291</sup> Exhibit 22942-X0163, Amended application, paragraph 102.

<sup>292</sup> Exhibit 22942-X0163, Amended application, paragraph 103.

<sup>293</sup> Exhibit 22942-X0015.01, PDF pages 4-5.

7 The ISO must determine the other system support services charge as the sum of:

(a) the highest metered demand in the settlement period multiplied by \$46.00/MW/month; and

(b) when power factor is less than 90% during the interval of highest metered demand in the settlement period, \$1,200.00/MVA multiplied by the apparent power difference calculated during the interval of highest metered demand in the settlement period as the difference between the metered apparent power and 111% of metered demand, unless the ISO waived the application of such a charge prior to December 31, 2016.

215. The AESO explained that the delivery of reactive power represents an obligation of the AESO, regardless of what causes the downstream requirements for that reactive power and this obligation results in a cost that should be borne by the “causer” of the reactive power.<sup>294</sup> The AESO submitted that because it is providing reactive power to support a DFO’s system, the cost of providing this support should be recovered from the DFOs whose system is being supported by the provision of reactive power from the transmission system.<sup>295</sup>

216. The AESO explained, “there are options available to a distribution system owner to address net reactive power required from the transmission system, including additional incentives for its end-use consumers or distribution-connected generators to further manage their reactive power requirements or through installation of reactive power devices on the electric distribution system.”<sup>296</sup> The AESO previously allowed for waivers to market participants who may face additional costs to address the power factor deficiency, compared to connections of new facilities.<sup>297</sup> The AESO further noted, “the cost of addressing power factor deficiencies after facilities have been constructed could remain significantly higher than the cost of doing so when initial decisions regarding configuration were being made.”<sup>298</sup> The AESO has proposed to “grandfather” services at which waivers had been previously granted and allow those waivers to continue in effect indefinitely.<sup>299</sup> The proposed grandfathering end date is December 31, 2016.<sup>300</sup> The AESO has also proposed to “no longer waive power factor deficiency charges at load sites with downstream generation, whether for a DFO or direct-connected end-use consumer.”<sup>301</sup>

217. Regarding its proposal to increase the power factor deficiency charge to \$1,200 per MVA, the AESO explained that the \$400 per MVA charge initially implemented in 1996 has not changed even though unit costs of utility equipment have increased between 233 per cent and 417 per cent, depending on the type of utility equipment.<sup>302</sup> Additionally, the AESO noted in determining the increase to \$1,200 that it examined the following: (i) the cost of adding capacitor banks on the transmission system; (ii) the power factor deficiency charges in DFO tariffs; and (iii) the cost to a market participant to add capacitors on its own facilities. The AESO added that

<sup>294</sup> Exhibit 22942-X0558, paragraph 163.

<sup>295</sup> Exhibit 22942-X0558, paragraph 166.

<sup>296</sup> Exhibit 22942-X0163, Amended application, paragraph 109.

<sup>297</sup> Exhibit 22942-X0163, Amended application, paragraph 110.

<sup>298</sup> Exhibit 22942-X0163, Amended application, paragraph 113.

<sup>299</sup> Exhibit 22942-X0163, Amended application, paragraph 111.

<sup>300</sup> Exhibit 22942-X0163, Amended application, paragraph 113.

<sup>301</sup> Exhibit 22942-X0163, Amended application, paragraph 110.

<sup>302</sup> Exhibit 22942-X0558, paragraph 175, specific utility equipment unit cost increases: distribution system capacitor bank 242 per cent increase, pole mounted transformer 417 per cent increase, pad mounted transformer 234 per cent increase, overhead conductor 233 per cent increase, underground cable 242 per cent increase and underground cable with conduit 225 per cent increase.

its proposed increase was not intended to be a precise calculation of each of these factors. Rather, it asserted that these factors simply provided a reasonable basis for the charge.<sup>303</sup> Further, because the AESO considered that economies of scale exist between transmission equipment and distribution equipment, it did not propose that the power factor deficiency charge be at a similar level to DFO rates, which range from \$3,500 per MVA to \$8,000 per MVA.<sup>304</sup>

218. With respect to its proposal to index the power factor deficiency charge, the AESO explained that the power factor deficiency charge would be indexed each year to the percentage weighted average increase in transmission system costs. The AESO provided a sample calculation in its IR responses<sup>305</sup> and noted that no party had opposed this proposal.<sup>306</sup>

219. The CCA, ATCO Electric and the DUC submitted concerns with the AESO's proposed changes to the power factor deficiency charge.

220. The CCA recommended that the AESO consider arrangements to phase out all power factor waivers within a reasonable time period because no evidence had been provided to support the view that the cost of addressing power factor deficiencies after facilities have been constructed are significantly higher than the cost of doing so when initial decisions regarding facility configurations are made.<sup>307</sup>

221. ATCO Electric opposed the AESO's proposed changes. It submitted that there is no evidence that low power factors are causing any problem to the operation of the transmission system. Therefore, it was of the view that the AESO's proposal will create a false price signal that will not be received by the intended recipients. It further asserted that the data used by the AESO to derive the revised power factor deficiency charge is unsubstantiated.<sup>308</sup> ATCO Electric argued that the AESO should adopt a more principle-based approach to addressing power factor issues and complete a detailed power factor study and that any solution should be delayed until evaluation, analysis and stakeholder consultation have been completed.<sup>309</sup>

222. ATCO Electric argued that the power factor deficiency charge works reasonably well for points of delivery with load customers only, but not for points of delivery with supply. In such circumstances, the power factor deficiency charge is not a valid indicator for measuring reactive power needs in circumstances where a DCG is connected to the point of delivery because the real power (MW) needs are reduced by DCG output, which significantly affects power factor at the point of delivery.<sup>310</sup> For example, ATCO Electric submitted that if generation has zero reactive power output, which means the reactive power needs at the point of delivery remain the same before and after the connection of a DCG, then the power factor would be degraded. As well, when a DCG draws reactive power from the system, it concurrently injects active power into the system, and the active power injected by the DCG reduces the active power demand at the point of delivery, which alleviates stress on the transmission system.<sup>311</sup> ATCO Electric added that modern DCG resources are not capable of operating at a power factor below 90 per cent due to

<sup>303</sup> Exhibit 22942-X0558, paragraph 172.

<sup>304</sup> Exhibit 22942-X0558, paragraphs 176-177.

<sup>305</sup> See AESO-AUC-2018NOV01-006(b).

<sup>306</sup> Exhibit 22942-X0558, paragraphs 179-180.

<sup>307</sup> Exhibit 22942-X0549, paragraphs 32-33.

<sup>308</sup> Exhibit 22942-X0553, paragraph 31.

<sup>309</sup> Exhibit 22942-X0553, paragraph 32.

<sup>310</sup> Exhibit 22942-X0553, paragraph 34.

<sup>311</sup> Exhibit 22942-X0553, paragraph 34.

their physical construction and because they are mandated by the DFO to operate pursuant to a constant power factor that already complies with the AESO's power factor requirements.<sup>312</sup> If the AESO's new tariff is implemented, ATCO Electric stated that "DCGs will be financially penalized, as the DFO will need to allocate any such power factor deficiency charge to the DCG owner or to load customers".<sup>313</sup>

223. ATCO Electric argued that the AESO's proposed power factor deficiency charge creates a false price signal in points of delivery with DCGs, as they already operate under the power factor parameters prescribed by the DFO and therefore there is no possible price signal to be sent to the DCG owner that can adjust the point of delivery power factor.<sup>314</sup>

224. ATCO Electric submitted that it had concerns with the data the AESO used to derive its \$1,200 per MVA because it did not account for how many capacitor banks had been installed solely for the purpose of power factor correction. The AESO used cost benchmarking data from 21 projects involving capacitor banks over a five-year period from 2010 to 2014 and assumed that one-half of the projects related to addressing power factor deficiencies. ATCO Electric stated that it had not installed capacitor banks on its transmission system since 2010 simply as a response to power factor deficiency but instead noted that the need for additional reactive power support is mainly driven by voltage issues associated with load growth and that it had installed capacitor banks to help with voltage issues. As well, ATCO Electric stated that the addition of any transmission capacitors would provide overall benefits to the local transmission system. Therefore, ATCO Electric argued that it is not correct to use historical costs associated with the addition of capacitor banks to determine the basis of cost recovery.<sup>315</sup>

225. DUC et al. argued that the AESO has and continues to charge the power factor deficiency charge incorrectly to dual-use customers and, therefore, these charges should be refunded. DUC et al. argued that the AESO's Rate DTS tariff applies to load customers only and before the AESO can charge a power factor deficiency charge, it must prove that the load customer has a load power factor less than 90 per cent. DUC et al. submitted that the AESO does not always have access to "revenue-approved metering data" to show that the load component of a dual-use site has a power factor below 90 per cent and, therefore, the AESO cannot impose the power factor deficiency charge on dual-use customers. DUC et al. also submitted that the AESO has billed customers improperly under the ISO tariff because the power factor deficiency charge billing determinants used for dual-use sites have been wrong.<sup>316</sup>

226. DUC et al. argued that "on nine occasions the AESO has reviewed this issue and found that they can not appropriately determine the load power factor for dual-use customers and have then issued a power factor charge waiver."<sup>317</sup> Therefore, DUC et al. stated "the appropriate course of action for the AESO should have been to issue power factor charge waivers to all similar dual-use customers where the load power factor cannot be accurately determined."<sup>318</sup> DUC et al. submitted that depending on metering configuration ( i.e. metering load and

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<sup>312</sup> Exhibit 22942-X0553, paragraph 35.

<sup>313</sup> Exhibit 22942-X0553, paragraph 42.

<sup>314</sup> Exhibit 22942-X0553, paragraph 37.

<sup>315</sup> Exhibit 22942-X0553, paragraphs 38-39.

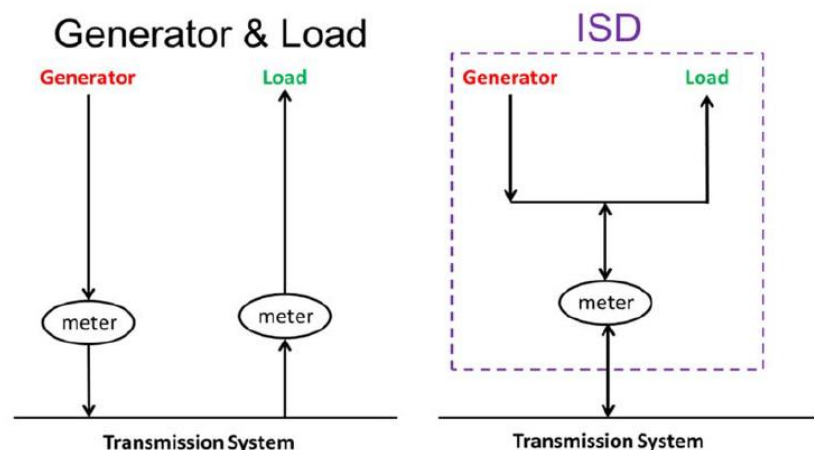
<sup>316</sup> Exhibit 22942-X0543, PDF page 8.

<sup>317</sup> Exhibit 22942-X0543, PDF page 9, line 3.

<sup>318</sup> Exhibit 22942-X0543, PDF page 9, line 5.

generation separately versus net metering), two identical dual-use customers are treated differently. DUC et al. provided the following figure:

**Figure 2. Power factor deficiency charge metering example<sup>319</sup>**



227. DUC et al. explained that for the generator and load metering configuration, in every metering interval, the generator meter would show that the power factor is compliant and the load meter would show that the load has a power factor greater than 90 per cent and that no power factor deficiency charge would apply. However, for the industrial system designation metering configuration, the net watts and net VARs lead to a derived power factor that can be less than 90 per cent and, therefore, cause the power factor deficiency charge to apply.<sup>320</sup> DUC et al. further advised that poor billing factors result when load and generation of a similar size are net metered at a point of delivery.<sup>321</sup>

228. DUC et al. argued that imposing a power factor deficiency charge to some dual-use customers and not others is undue discrimination and results in inter-customer subsidies. Additionally dual-use customers who provide reactive power should not be charged an additional fee, especially since dual-use customers cannot manage their reactive power production due to the AESO mandating the generation power factor to dual-use generators.<sup>322</sup> DUC et al. submitted that because dual-use customers are paying for regional and point of delivery charges, also charging them power factor deficiency charges at some locations but not others is unfair, discriminatory and not based on cost causation.<sup>323</sup>

229. DUC et al. recommended that all power factor deficiency charges levied on dual-use customers be refunded because the power factor deficiency charges have been based on incorrect billing determinants and the AESO has been aware of the charges since at least 2003. DUC et al. described three situations where an approved tariff was not being applied properly and the AESO provided full refunds.<sup>324</sup> Additionally, DUC et al. submitted that this proceeding is different to the Primary Service Credit case in the 2015 Deferral Account Reconciliation proceeding<sup>325</sup>

<sup>319</sup> Exhibit 22942-X0543, PDF page 9

<sup>320</sup> Exhibit 22942-X0543, PDF pages 9-10.

<sup>321</sup> Exhibit 22942-X0543, PDF pages 10-11.

<sup>322</sup> Exhibit 22942-X0543, PDF pages 10 and 13.

<sup>323</sup> Exhibit 22942-X0563, PDF page 4.

<sup>324</sup> Exhibit 22942-X0543, PDF pages 14-15.

<sup>325</sup> Proceeding 21735: AESO 2015 Deferral Account Reconciliation Application.

because DUC et al. is not requesting a change in that tariff allocation methodology but instead requesting that the approved power factor deficiency charge be properly and consistently applied to all dual-use customers.<sup>326</sup> DUC et al. argued that its request to refund the power factor deficiency charge is not retroactive ratemaking because DUC et al. is not asking the Commission to change the power factor deficiency charge rate but instead is asking for the rate to be applied properly and consistently to all dual-use customers because, for the dual-use customers who did not obtain a power factor waiver, the power factor deficiency charge was improperly applied.<sup>327</sup>

230. In argument, DUC et al. submitted that the AESO's concern with the power factor deficiency charge is that customers may be imposing greater utilization of local wires assets that are not fully reflected in the billing capacity billing determinant. DUC et al. agreed with the AESO concern with respect to the utilization of transmission wires, but recommended a revised rate structure that would ensure every customer would pay a fair contribution towards the recovery of regional and point of delivery costs.<sup>328</sup> The AESO's current rate design using the billing capacity billing determinant is the greater of:<sup>329</sup>

- (i) Peak measured demand each month, in kW
- (ii) 90 per cent of DTS contract capacity
- (iii) 90 per cent of highest peak measured demand (item 1 above) in the last 23 months (ratchet)

231. Instead, DUC et al. proposed that billing capacity be defined as the greater of:<sup>330</sup>

- (i) Peak measured demand each month, in kW
- (ii) 90 per cent of peak measured demand each month, in kVA
- (iii) 90 per cent of DTS contract capacity
- (iv) 90 per cent of highest peak measured demand (items 1 and 2 above) in the last 23 months (ratchet)

232. DUC et al. submitted that this change would offer the following improvements over the AESO's current and proposed tariff:<sup>331</sup>

- Load customers with a poor power factor will be provided with a much stronger price signal to correct their power factor
- Better price alignment with the DFO tariffs
- Dual-use customers who may require the import of reactive power will appropriately pay for local wires related costs
- Eliminates the need for the power factor deficiency charge

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<sup>326</sup> Exhibit 22942-X0543, PDF pages 16-17.

<sup>327</sup> Exhibit 22942-X0543, PDF page 18.

<sup>328</sup> Exhibit 22942-X0543, PDF pages 18-19.

<sup>329</sup> Exhibit 22942-X0543, PDF page 18.

<sup>330</sup> Exhibit 22942-X0543, PDF page 19.

<sup>331</sup> Exhibit 22942-X0543, PDF page 19.



- Eliminates the need for power factor deficiency waivers

233. DUC et al. submitted that on a go-forward basis for the 2018 ISO tariff, the Billing Capacity definition should include the 90 per cent of peak kVA provision and the power factor deficiency charge should be removed. DUC et al. also noted that all the issues brought up by the CCA and ATCO Electric in their arguments could be resolved by adding the 90 per cent provision to the definition of billing capacity and removing the power factor deficiency charge.<sup>332</sup>

234. The AESO replied to ATCO Electric stating that it has not suggested that the low power factor has created any operational issues that it has been unable to address, but instead it is proposing changes to apply the power factor deficiency charge more consistently to the causer of those charges by no longer waiving those charges at load sites with downstream generation, and by increasing the power factor deficiency charge to reflect a “current basis for the charge.”<sup>333</sup> The AESO also stated that the intended recipient of the price signal for the power factor deficiency charge is the customer to whom system access service is provided under Rate DTS, and in the case of ATCO Electric, it would be ATCO Electric itself, not the end-use customers or DCGs, that would be the recipient of the price signal. It would then be up to ATCO Electric to respond accordingly, and the AESO does not propose to restrict that response.<sup>334</sup>

235. Regarding the increase in the power factor deficiency charge to \$1,200 per MVA and ATCO Electric’s suggestion that the AESO should complete a detailed power factor study, the AESO replied that it has already conducted an examination of this cost and that a more precise value is not required. The AESO submitted that the disconnect between the current charge and other benchmarks, as well as the increase in costs for transmission equipment over the same period of 1996 to 2018, all support the proposed increase.<sup>335</sup>

236. The AESO submitted that the costs of serving customers’ reactive power needs represent an obligation for the AESO, regardless of what causes the downstream requirement for reactive power and does not differ whether the need arises at points of delivery with load customers only or at points of delivery where DCGs also exist.<sup>336</sup> The AESO stated ATCO Electric has mischaracterized the application of the power factor deficiency charge and noted that even when a DCG has zero reactive power output, the power factor deficiency charge is determined during the interval of highest metered demand in the settlement period, and at this time there would likely be little active power injected by the DCG and the transmission system would be at a point where it may be experiencing significant stress.<sup>337</sup>

237. The AESO replied to DUC et al. stating that it is fully able to properly, accurately and legally determine the Rate DTS power factor deficiency charge at dual-use sites. The AESO explained that based on the ISO tariff, the power factor deficiency charge is one component of Rate DTS, and Rate DTS “applies to system access service provided at a point of delivery,”<sup>338</sup> where point of delivery means “the point at which electricity is transferred from transmission facilities to facilities owned by a market participant receiving system access service under the

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<sup>332</sup> Exhibit 22942-X0563, PDF pages 4-5.

<sup>333</sup> Exhibit 22942-X0578, paragraph 119.

<sup>334</sup> Exhibit 22942-X0578, paragraph 120.

<sup>335</sup> Exhibit 22942-X0578, paragraph 122.

<sup>336</sup> Exhibit 22942-X0578, paragraph 125.

<sup>337</sup> Exhibit 22942-X0578, paragraph 126.

<sup>338</sup> Exhibit 22942-X0014.03, Appendix R – Proposed 2018 ISO Tariff, Rate DTS, subsection 1, PDF page 3.

ISO tariff, including an electric distribution system.”<sup>339</sup> The AESO submitted that Rate DTS applies to points of delivery where electricity is withdrawn from the transmission system whether that point of delivery serves load only or load and generation. Regarding dual-use sites, power factor deficiency charges apply only when load exceeds generation and are based on the interval when load exceeds generation by the greatest amount or when the generation is off-line and load is greatest.<sup>340</sup> Therefore, the AESO submitted that the availability of metering beyond the point of delivery is irrelevant because Rate DTS applies at the point of delivery. The AESO noted that metering is always available at the point of delivery and that metering at the point of delivery is consistent with the other billing determinants used to determine other Rate DTS charges and the point of delivery is where the AESO’s obligation to provide system access service is realized.<sup>341</sup>

238. DUC et al. provided a metering example for two dual-use sites with different metering configurations, one with separate load and generation metering and one with net metering. In response, the AESO argued that the two configurations are clearly not identical because in the separately metered configuration, the AESO provides system access service to the full load, and in the net metered configuration, the AESO provides system access service only to load when it exceeds generation and only to the extent that the load exceeds generation. Additionally, the AESO stated that it is immaterial whether dual-use sites provide reactive power because Rate DTS only applies when site load exceeds site generation and in those intervals, it is reasonable and appropriate to assess a power factor deficiency charge for dual-use sites consistent with the determination of power factor deficiency charges for all other points of delivery.<sup>342</sup>

239. The AESO submitted that the billing determinants used for dual-use sites are correct and determined in accordance with the ISO tariffs approved by the Commission. The AESO is not aware of any complaint to the Commission regarding its power factor deficiency charge at any time since 2003 or of any challenge to the power factor deficiency charge over the course of several ISO tariff applications.<sup>343</sup> Further, the AESO stated that a waiver of charges for nine of more than 500 services cannot be considered a precedent for extending that waiver to significantly more services.<sup>344</sup>

240. With respect to DUC et al.’s suggested revised rate design, the AESO stated that it did not consider that the power factor deficiency charge needed to be in alignment with the DFO tariffs because there are economies of scale between transmission equipment and distribution equipment.<sup>345</sup>

241. No party commented on the AESO’s proposal to index the power factor deficiency charge to the weighted average increase in transmission costs.

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<sup>339</sup> Exhibit 22942-X0014.01, Appendix U – Defined Terms Used in the ISO Tariff, PDF page 7.

<sup>340</sup> Exhibit 22942-X0578, paragraph 130.

<sup>341</sup> Exhibit 22942-X0578, paragraph 131.

<sup>342</sup> Exhibit 22942-X0578, paragraphs 132-133.

<sup>343</sup> Exhibit 22942-X0447, paragraph 57.

<sup>344</sup> Exhibit 22942-X0578, paragraph 128.

<sup>345</sup> Exhibit 22942-X0578, paragraph 134.

## Commission findings

242. The Commission has organized its findings in respect of the AESO's proposed power factor deficiency charge under separate subheadings as follows:

- The authority of the AESO to apply the power factor deficiency charge.
- The effect of the proposed power factor deficiency charge on dual-use customers.
- The reasonableness of the AESO's proposed increase in the amount of the power factor deficiency charge from \$400 per MVA to \$1,200 per MVA.
- Proposals to address power factor deficiency concerns through future rate design changes.

## Authority to apply power factor deficiency charge

243. The Commission notes that the ISO tariff includes the following definitions:

“system access service” as defined in the Act means the service obtained by market participants through a connection to the transmission system, and includes access to exchange electric energy and ancillary services.

“point of delivery” means the point at which electricity is transferred from transmission facilities to facilities owned by a market participant receiving system access service under the ISO tariff, including an electric distribution system.

“electric distribution system” as defined in the Act means the plant, works, equipment, systems and services necessary to distribute electricity in a service area, but does not include a generating unit or a transmission facility.

“market participant” means: as defined in the Act, any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services; or any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or ancillary services; and a person who requests system access service from the ISO.

244. Having regard to the definitions above, the definition of “system access service” includes those market participants that connect to a transmission system. The definition of “point of delivery” is the point at which electricity is transferred from transmission facilities to the facilities owned by a market participant receiving system access service. A dual-use site connects to a transmission system and may transfer electricity from the transmission facilities to other facilities, as load. A dual-use site may also generate and transfer electricity from other facilities to transmission system facilities, as generation. The application of Rate DTS is not limited to load or generation in subsection 7(b) of Rate DTS, but instead, is applicable to the service at the point where a market participant is capable of transferring electricity from the transmission facilities to facilities owned by it. With respect to a dual-use site, this point may be the same point at which electricity is transferred from generation facilities to the transmission system. Therefore, the power factor deficiency charge is applicable to both load and generation at the same site.

245. The Commission notes that the AESO has argued that it satisfies its obligation to provide transmission services at the POD where electricity is transferred from transmission facilities to

facilities owned by a market participant and, therefore, Rate DTS charges must be determined at the POD and not at a point of on-site load or generation beyond the POD. The AESO noted that this is consistent with other billing determinants used to determine other Rate DTS charges. The AESO submitted, the “DUC has provided no specific information on which billing determinant it considered to be incorrect in Rate DTS or how that billing determinant should be corrected.”<sup>346</sup> The AESO further submitted that DUC et al.’s claim that the AESO used incorrect billing determinants should be dismissed.

246. The Commission agrees with the AESO that system access service is provided at the POD, and that point is where a market participant is capable of transferring electricity from the transmission facilities to its facilities, or at which a market participant is capable of transferring electricity onto the transmission system. For a dual-use customer, the point at which energy is transferred from and to the transmission system may be the same physical location. The Commission also finds that Rate DTS applies to any point at which both a transfer from or to the transmission system occurs. The Commission dismisses the claim by DUC et al. that the AESO has used incorrect billing determinants in Rate DTS.

247. The Commission finds that the AESO has been applying Rate DTS and the power factor deficiency charge in accordance with the approved and current ISO tariff and, therefore, the AESO may determine a Rate DTS power factor deficiency charge at all delivery points of system access service, including PODs that connect dual-use sites.

### **Effect of power factor deficiency charge on dual-use customers**

248. The DUC, in its evidence, considered that the application of the AESO’s proposed power factor deficiency charge to dual-use sites that are subject to totalized billing gives rise to a measurement error. Specifically, it suggested that the measurement of reactive power at the POD for totalized dual-use sites causes the appearance of reactive power deficiencies that would not occur if reactive power were to be measured separately for DTS and STS at the dual-use site. Consequently, the measurement error created by metering the net load at the totalized POD for a dual-use site would give rise to a charge for a reactive power deficiency that must be mitigated in some other fashion, such as by granting a waiver of the charge.

249. The Commission agrees with the AESO that the delivery of reactive power to a POD represents an obligation for the AESO, regardless of what causes the downstream requirements for reactive power. This obligation may result in costs on the transmission system. The Commission also agrees that such costs should generally be attributed to the “causer” of the reactive power requirement. The Commission understands that a DFO may address net reactive power required by introducing incentives to end-use customers or DCG proponents to manage their reactive power requirements or by installing reactive power devices on the electric distribution system.

250. Accordingly, the Commission finds that granting a waiver to DCG proponents could frustrate the DFOs’ ability to manage net reactive power requirements on their systems.

251. The Commission also understands that the AESO had previously made a determination to waive the application of the power factor deficiency charge to a limited number of market participants, nine out of more than 500, with previously built facilities. The AESO determined

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<sup>346</sup> Exhibit 22942-X0558, paragraph 168.

that, on a go forward basis, “the cost of addressing power factor deficiencies after facilities have been constructed could remain significantly higher than the cost of doing so when initial decisions regarding configuration were being made.”<sup>347</sup> The Commission considers that it is reasonable for the AESO to continue to grandfather the waivers for these market participants indefinitely. This is because to do otherwise would unfairly treat market participants who had relied on the AESO’s prior determination to grant a waiver when making investment decisions.

252. For the above reasons, the Commission denies DUC et al.’s request to extend waivers to additional customers.

### **Proposed increase in amount of power factor deficiency charge**

253. Based on the evidence provided in the current proceeding, the Commission is not satisfied that the AESO has sufficiently justified its proposed increase in the charge from \$400 per MVA to \$1,200 per MVA. In particular, the Commission accepts the concerns identified by ATCO Electric that the information relied on by the AESO to develop its proposed charge of may have overstated the costs of adding capacitor banks specifically for the purposes of mitigating reactive power concerns, and that the AESO’s calculation did not adequately take into account that capacitor banks may be installed to provide other benefits to the local transmission system.

254. Given these concerns, the AESO’s proposed change to the existing power factor deficiency charge to \$1,200 per MVA from \$400 per MVA is denied. The Commission agrees with the AESO that an increase to the charge is required, but the Commission has not been persuaded by the AESO that an increase to \$1,200 per MVA is the appropriate amount. Considering this finding, the AESO’s proposal to index the power factor deficiency charge to the weighted average increase in transmission system costs is also denied. The AESO is directed to either provide further support for its calculation of the \$1,200 per MVA charge in the compliance filing to this decision or in its next comprehensive GTA.

### **Consideration of power factor deficiency issues in future ISO tariff development**

255. The Commission notes that the AESO’s power factor deficiency charge is currently recovered under the ISO tariff’s Other System Support Services Charge based on billing capacity as follows:

- “billing capacity” means, at a point of delivery, the highest of
- (i) the highest 15-minute metered demand in the settlement period;
  - (ii) 90% of the highest metered demand in the 24-month period including and ending with the settlement period, but excluding any months during which commissioning occurs; or
  - (iii) 90% of the contract capacity or, when the settlement period contains a transaction under Rate DOS, 100% of the contract capacity.<sup>348</sup> [bolding removed]

256. Further, the current ISO tariff defines “metered demand” as:

<sup>347</sup> Exhibit 22942-X0163, Amended application, paragraph 113.

<sup>348</sup> Exhibit 22942-X0017.01, Appendix U – Defined Terms Used in the ISO Tariff, PDF page 2

“metered demand” means the rate at which electric energy is delivered to a point of delivery or from a point of supply, in MW, measured by the relevant metering equipment and averaged over a 15-minute or other interval as deemed necessary by the ISO.<sup>349</sup>

257. The Commission notes that the DUC, in its opening statement at the oral hearing suggested a revised rate design where billing capacity would include kVA’s (reactive power) in addition to kW (real power) only. The Commission considers that raising this proposal at that time did not provide parties, and particularly the AESO, with sufficient opportunity to examine this proposal. The Commission is not prepared to direct the AESO to implement a different rate design for this 2018 ISO tariff. However, the Commission is interested in further development of this approach.

258. Accordingly, the AESO is directed in its next comprehensive GTA to provide a discussion of possible revised rate design structures for billing capacity and to discuss if the use of reactive power was considered in the revised rate design structures.

### 5.3 Rate DTS: Bill impact analysis

259. The AESO completed an analysis in Appendix I<sup>350</sup> to the application of the impacts on market participants’ bills of the Rate DTS changes proposed. Based on previous direction from the Commission, the AESO compared in Appendix I, on a per-point-of-delivery basis, bills under the proposed 2018 Rate DTS to bills under the 2017 Rate DTS and noted that this comparison illustrates the impact of changes to transmission cost functionalization and classification.<sup>351</sup> The AESO did not propose any rate modifications or additional rates or rides to mitigate bill impacts arising from its proposed 2018 Rate DTS.<sup>352</sup>

260. In its evidence, the DUC noted several concerns with the AESO’s bill impact analysis in Appendix I, specifically:<sup>353</sup>

- It does not contain formulas that can be used to verify or replicate the tariff charges.
- The billing determinants for each point of delivery are for the period of 2014 to 2016 and therefore are 24 months out of date.
- The AESO used pool prices from the 2014 to 2016 period, which were less than the forecasted and actual pool price for 2018.
- It is unclear how the bulk demand coincident demand billing determinant for each point of delivery is determined by the AESO.
- The AESO has used pivot tables for some statistics and used the simple average instead of a weighted average and this could provide misleading results.

261. The DUC’s evidence noted that when it made changes to Appendix I the main difference between the AESO model and the DUC model was that the DUC used a higher pool price which therefore increased the commodity charges and led to overall lower percentage bill increases.<sup>354</sup>

<sup>349</sup> Exhibit 22942-X0017.01, Appendix U – Defined Terms Used in the ISO Tariff, PDF page 6.

<sup>350</sup> Exhibit 22942-X0005.03, Appendix I – 2018 Bill Impact Analysis.

<sup>351</sup> Exhibit 22942-X0163, Amended application, paragraphs 123-127.

<sup>352</sup> Exhibit 22942-X0163, Amended application, paragraphs 128-132.

<sup>353</sup> Exhibit 22942-X0336, PDF page 33.

<sup>354</sup> Exhibit 22942-X0336, PDF pages 33-34.

The DUC noted that the largest bill impacts in its analysis are proposed for non-load points of delivery, with industrial system designations, dual-use customers and generation receiving significantly higher rate increases. These increases result primarily from the updated Transmission System Cost Causation Study where the AESO proposed to shift costs from Bulk to Regional and point of delivery.<sup>355</sup> DUC et al. recommended that for the next tariff proceeding the AESO's Appendix I bill impact spreadsheet be revised to provide a better tool to test the impact of various rate proposals.<sup>356</sup>

262. The AESO submitted that the Appendix I bill impact workbook provides a reasonable assessment of bill impacts over the 2018 to 2020 timeframe.<sup>357</sup> The AESO explained that formulas had not been included in Appendix I because it uses commercially sensitive detailed billing data to perform the bill impact analysis, and to maintain confidentiality the AESO unlinks Appendix I from such data sources which results in cells showing values instead of formulas or references.<sup>358</sup> Regarding the use of billing determinants for the 2014-2016 period, the AESO stated 2018 actual billing determinants were not available at the time of the amended application and that billing determinants have not changed materially from the 2014 to 2016 period.<sup>359</sup> The AESO submitted that it could update the Appendix I bill impact workbook using the latest billing determinants available if directed to do so by the Commission in its compliance filing to this application.<sup>360</sup>

263. The AESO disagreed with DUC et al.'s suggestion to use derived billing determinants for bulk demand when actual coincident metered demand billing determinants are available for each point of delivery and noted that the effect of change in pool price on bill impacts is well understood and if hourly pool prices differ from 2016, the actual bill impact will reflect the difference. The AESO also disagreed with DUC et al.'s recommendation of using a weighted average instead of a simple average, as a weighted average places more weight on points of delivery with higher monthly bills and therefore values the impact on these points of delivery more than other points of delivery; the AESO values the impact on all points of delivery the same and a simple average reflects that.<sup>361</sup>

### Commission findings

264. The Commission has reviewed Appendix I and agrees with the AESO that it provides a reasonable assessment of the bill impacts over the 2018-2020 timeframe. Additionally, the Commission finds that Appendix I was intended by the AESO to be used for information purposes only and not as a working model for parties to test the impact of rate proposals. The Commission finds that Appendix I contains sensitive information of detailed billing data from the AESO and therefore finds that formulas and references should not be included in Appendix I or in similar models based on such detailed AESO billing data. Further, the Commission considers that Appendix I (the bill impact analysis spreadsheet) contains enough information and data for parties to perform additional point of delivery analysis, which was demonstrated by the DUC in its own similar analysis.

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<sup>355</sup> Exhibit 22942-X0336, PDF pages 35-36.

<sup>356</sup> Exhibit 22942-X0543, PDF page 5.

<sup>357</sup> Exhibit 22942-X0558, paragraph 146.

<sup>358</sup> Exhibit 22942-X0257, AESO-AE-2018NOV01-009(a), PDF page 19.

<sup>359</sup> Exhibit 22942-X0447, paragraphs 20-22.

<sup>360</sup> Exhibit 22942-X0558, paragraphs 147-148.

<sup>361</sup> Exhibit 22942-X0558, paragraphs 145-146.

265. The Commission directs the AESO to continue including this type of analysis in its future comprehensive GTAs.

## 6 Other rates and riders

### 6.1 Other rates and riders: Primary Service Credit and Rate PSC

266. Rate PSC provides a credit to a market participant who does not utilize transformation facilities owned by a transmission facility owner. Instead, the transformation facilities used by the market participant are generally purchased, owned, and operated by the market participant instead of by a transmission facility owner.<sup>362</sup>

267. The primary service credit (PSC) is the sum of the products calculated by multiplying the volume and credit in each row (a) through (e) of the following table.<sup>363</sup>

**Table 9. Primary service credit amounts**

Volume in <b>Settlement Period</b>	<b>Credit</b>
(a) <b>Substation fraction</b>	\$7,995.00/month
(b) First $(7.5 \times \text{substation fraction})$ MW of <b>billing capacity</b>	\$3,245.00/MW/month
(c) Next $(9.5 \times \text{substation fraction})$ MW of <b>billing capacity</b>	\$2,032.00/MW/month
(d) Next $(23 \times \text{substation fraction})$ MW of <b>billing capacity</b>	\$1,421.00/MW/month
(e) All remaining MW of <b>billing capacity</b>	\$1,162.00/MW/month

### Commission findings

268. In Decision 22942-D01-2017, the Commission approved the AESO's proposed changes to its deferral account reconciliation methodology, Rider C and Rate PSC on an interim basis. The Commission approved the changes on an interim basis, in part, because "parties either took no position, did not object or indicated support for the request."

269. No objections to the AESO's proposed changes to Rate PSC were submitted in this proceeding nor was any evidence provided to demonstrate that the AESO's proposed changes to Rate PSC were unjust, unreasonable or unduly preferential, arbitrary or discriminatory. Therefore, the Commission approves the AESO's proposed Rate PSC, as final.

### 6.2 Other rates and riders: Rider C and associated deferral account processes

270. In accordance with Section 14 of the *Electric Utilities Act*, the AESO uses deferral accounts to ensure no profit or loss results from the AESO's operation on an annual basis. The AESO's use of deferral accounts is incorporated in the ISO tariff through Rider C, Deferral Account Adjustment Rider. Deferral accounts allow the AESO to settle differences between actual costs and revenues incurred in providing system access service to market participants.

<sup>362</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, PDF pages 19.

<sup>363</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, PDF pages 19.



271. Section 14 of the *Electric Utilities Act* states:<sup>364</sup>

ISO budget

**14(1)** The Independent System Operator must prepare a budget for each fiscal year setting out

- (a) the estimated expenditures, costs and expenses of the Independent System Operator to carry out its powers, duties, responsibilities and functions, which may include expenditures for capital assets allocated over the expected useful life of the asset,
- (b) the aggregate estimated expenditures, costs and expenses in the approved budget of the Market Surveillance Administrator,
- (c) its estimated revenue from ISO fees,
- (d) its estimated revenue from the ISO tariff, and
- (e) its estimated revenue from fees levied and payments received under the Renewable Electricity Act.

**(2)** The Independent System Operator may amend its budget.

**(3)** The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation.

272. In Decision 2014-242, the Commission issued the following direction:

The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.<sup>365</sup>

273. In Decision 21735-D02-2017,<sup>366</sup> regarding the AESO 2015 deferral account reconciliation, the Commission provided the following further direction:

... Nonetheless, the Commission expects the AESO to follow through on its commitment to further consult with stakeholders on this issue and directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application.<sup>367</sup>

274. In compliance with the directions issued by the Commission, the AESO undertook a review of Rider C and the deferral account reconciliation methodology.<sup>368</sup> Based on its review,

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<sup>364</sup> *Electric Utilities Act*, Section 14, page 23.

<sup>365</sup> Decision 2014-242, paragraph 704.

<sup>366</sup> Decision 21735-D02-2017: Alberta Electric System Operator, 2015 Deferral Account Reconciliation, Proceeding 21735, March 14, 2017.

<sup>367</sup> Decision 21735-D02-2017, paragraph 108.

<sup>368</sup> Exhibit 22942-X0008, Appendix L - Examination of Rider C and Deferral Account Reconciliation Methodology Report.

the AESO proposed changes to Rider C and the deferral account reconciliation methodology in the application.

275. The AESO proposed the following changes to Rider C:<sup>369</sup>

- (i) Rider C is proposed to be determined as an additional percentage charge or credit that applies to each of the components of Rates DTS and FTS (Fort Nelson demand transmission service), rather than as an additional \$/MWh charge or credit as currently approved;
- (ii) Rider C is proposed to be calculated to minimize year-end deferral account balances, rather than to minimize balances at the end of the upcoming calendar quarter as currently approved. Rider C will continue to be set on a quarterly basis, but will be calculated every quarter to recover or refund all accumulated and forecast differences between anticipated costs and actual costs on a calendar year basis. The AESO proposes to continue to have the discretion to recover or refund such differences over a longer period to minimize rate impact; and
- (iii) Rider C is proposed to also apply to Rate PSC, also as an additional percentage charge or credit.

276. The AESO proposed two changes to its deferral account reconciliation methodology:<sup>370</sup>

- (i) The deferral accounts are proposed to be reconciled on a production year basis, rather than on a production month basis as currently approved. This change aligns with the proposed calculation of Rider C to minimize year-end deferral account balances; and
- (ii) Deferral account balances are proposed to be allocated based on revenue by rate component of Rates DTS and Rate FTS, net of credits of Rate PSC. This change aligns with the proposed application of Rider C to Rate PSC.

277. The revised Rider C – Deferral Account Adjustment Rider provisions are found in Appendix R of the AESO’s proposed 2018 ISO tariff.<sup>371</sup>

### Commission finding

278. In Decision 22942-D01-2017,<sup>372</sup> the Commission approved the AESO’s proposed changes to its deferral account reconciliation methodology, Rider C and Rate PSC on an interim basis. The Commission approved the changes on an interim basis, in part, because “parties either took no position, did not object or indicated support for the request.”<sup>373</sup>

279. No objections to the AESO’s proposed changes to its deferral account reconciliation methodology or Rider C were submitted, nor was any evidence provided to demonstrate that the

<sup>369</sup> Exhibit 22942-X0163, Amended application, paragraph 146.

<sup>370</sup> Exhibit 22942-X0163, Amended application, paragraph 147.

<sup>371</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, PDF pages 42-43.

<sup>372</sup> Decision 22942-D01-2017: Alberta Electric System Operator, 2018 Independent System Operator Tariff – Interim Approval, Proceeding 22942, November 28, 2017.

<sup>373</sup> Decision 22942-D01-2017, paragraph 10.

AESO's proposed changes to its methodology or Rider C were unjust, unreasonable or unduly preferential, arbitrary or discriminatory. Therefore, the Commission approves the AESO's proposed changes to its deferral account reconciliation methodology and Rider C, as final.

### 6.3 Other rates and riders: Rider F – Balancing Pool Consumer Allocation Rider

280. The Balancing Pool is a corporation established in Section 75 of the *Electric Utilities Act* to carry out the powers and duties set out therein.<sup>374</sup> Pursuant to Section 82 of the *Electric Utilities Act*, the Balancing Pool must prepare a budget for each fiscal year setting out its estimated revenues and expenses. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to (or collected from) electricity market participants over the year.

281. Following receipt of the Balancing Pool's "annualized amount," the AESO is required to include this amount in its tariff.<sup>375</sup>

282. The AESO collects (or refunds) from (or to) market participants the Balancing Pool's annualized amount through Rider F. Rider F applies to the following customers:<sup>376</sup>

**1(1)** Rider F of the **ISO tariff**, *Balancing Pool Consumer Allocation Rider*, applies to **system access service** provided under:

(a) Rate DTS of the **ISO tariff**, *Demand Transmission Service*; and

(b) Rate DOS of the **ISO tariff**, *Demand Opportunity Service*.

**1(2)** Notwithstanding subsection 1(1) above, Rider F does not apply to **system access service** provided to:

(a) the City of Medicine Hat; or

(b) BC Hydro at Fort Nelson, British Columbia.

283. The AESO did not propose any changes to its Rider F - *Balancing Pool Consumer Allocation Rider* methodology in the application. However, it stated that Rider F would be updated for 2019 in a separate application in the fourth quarter of 2018.<sup>377</sup> The AESO filed its updated Rider F application on November 6, 2018, for 2019 and the application was approved by the Commission in Decision 24037-D01-2018.<sup>378</sup> The methodology remained unchanged.

284. No objections to the method used by the AESO, to determine the rate charged, were submitted in this proceeding.

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<sup>374</sup> The Balancing Pool duties are set out in Section 85 of the *Electric Utilities Act*.

<sup>375</sup> Sections 82(5) and (6) of the *Electric Utilities Act*.

<sup>376</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, ISO Tariff – Rider F – Balancing Pool Consumer Allocation Rider, PDF page 45.

<sup>377</sup> Exhibit 22942-X0163, Amended application, paragraph 86.

<sup>378</sup> Decision 24037-D01-2018: Alberta Electric System Operator, 2019 Balancing Pool Consumer Allocation Rider F, Proceeding 24037, November 26, 2018.

## Commission findings

285. Pursuant to Section 82(6)(b) of the *Electric Utilities Act*, the Commission must “approve, with or without modification, the allocation of the annualized amount to the owners of electric distribution systems, industrial systems and persons that have made arrangements under Section 101(2),” being Rate DTS and Rate Demand Opportunity Service market participants.

286. The Commission has found that the AESO’s approach to calculating Rider F has been reasonable in the past. In the absence of objections to the allocation proposed or any evidence provided to demonstrate that the AESO’s approach to calculating Rider F is unjust, unreasonable or unduly preferential, arbitrary or discriminatory, the Commission approves the method by which the AESO has determined the Rider F charge.

287. The Commission notes that a \$2.90/MWh charge for 2019 consumption was approved in Decision 24037-D01-2018. This amount supersedes the charge of \$3.10/MWh included by the AESO in the application.

## 6.4 Other rates and riders: Rider J – Wind Forecasting Service Costs Recovery

288. In 2010, the AESO implemented a centralized wind forecasting service for Alberta. It did so as part of its ongoing efforts to integrate more wind power on the interconnected electric system. The wind forecast service is intended to assist the AESO in making risk assessments and operational decisions to ensure reliable operation of the transmission system. Wind generators pay the cost of the wind forecasting service, similar to other generators that bear their own cost of providing forecast data. The cost of this service is collected through the Rider J charge.

289. The AESO calculates the Rider J charge as the product of metered energy in the settlement period multiplied by \$0.09/MWh.<sup>379</sup>

290. The AESO updates Rider J in its annual ISO tariff update application, in the following year, to ensure the revenue and costs for wind forecasting do not result in a shortfall or surplus.

291. The AESO did not propose changes to Rider J - Wind Forecasting Service Cost Recovery Rider in the application, stating that Rider J was updated in the 2018 ISO tariff update application and approved by the Commission in Decision 23065-D01-2017<sup>380 381</sup>

## Commission findings

292. The Commission approved the AESO’s Rider J in Decision 2010-606, finding that providing this service was more efficient and effective as compared to having wind generators perform this service individually. Further, the Commission determined that because wind generators are the recipients of the required wind forecasting, that it was appropriate for wind generators to bear this cost as doing so is consistent with the principles of cost causation. The Commission continues to hold these views.

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<sup>379</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, ISO Tariff – Rider J – Wind forecasting service cost recovery Rider, Section 2(2), PDF page 47.

<sup>380</sup> Decision 23065-D01-2017: Alberta Electric System Operator, 2018 Independent System Operator Tariff Update, Proceeding 23065, November 28, 2017.

<sup>381</sup> Exhibit 22942-X0163, Amended application, paragraph 86.

293. Rider J rate was updated in the 2018 ISO tariff update application and approved by the Commission in Decision 23065-D01-2017. The Commission finds that the AESO's methodology to calculate the Rider J charge, and the rate of \$0.09/MWh, continues to be reasonable and it is approved.

## **6.5 Other rates and riders: Duplication avoidance rate riders (Dow Chemical Extension)**

294. In Section 6.2 of the application, the AESO discussed Rider A1, which applies a duplication avoidance tariff (DAT) rate rider on behalf of Dow Chemical Canada Inc. Rider A1, approved in 1998 in Decision U98125, is set to expire in 2021. The AESO requested Commission approval to extend Rider A1 for an additional 20 years to 2041, and to update the rider and approve updates to certain terms and conditions related to the rider.<sup>382</sup>

295. The AESO requested this extension to the term of Rider A1 on the basis that the extended term reflects the estimated lifespan of the bypass facilities, had they been built by Dow. It added that because Dow has already paid the capital cost of the proposed bypass, the rate rider would be limited to operations and maintenance costs and losses during the 20 year extension. Further, the AESO submitted that:

The forecast benefits for 1998 through to 2021 have been removed from the table to reflect that Dow Canada Inc. made the forecast benefit payments as two monetary contributions totaling \$5,071,038, consisting of (i) \$4,656,038 in capital costs and (ii) \$415,000 in future operating and maintenance costs, losses and spare inventory costs to TransAlta in 1997 and 1998.<sup>383</sup>

296. In AESO-AUC-2018NOV01-017(d), the Commission asked the AESO the following:

Does the AESO agree that, for the purposes of demonstrating that it has a credible threat of bypass, a market participant seeking a DAT should be able to demonstrate that a viable option of bypass must exist without any access to back-up electrical supply from the Alberta Interconnected Electric System (AIES)? If the AESO does not agree, please explain.

297. The AESO's response was as follows:

No, the AESO does not agree. A credible threat of bypass would exist if a physical alternative would allow electricity to be transmitted from a generating unit to load facilities such that, in doing so, the transmission system is bypassed and the system access service provided to the load facilities is significantly reduced. Back-up electrical supply could still be accessed from the Alberta interconnected electric system, although the AESO would anticipate that the back-up demand would be considerably less than the full-load demand that would normally be served through the bypass facilities.

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<sup>382</sup> Exhibit 22942-X0163, paragraph 152.

<sup>383</sup> Exhibit 22942-X0002.01, paragraph 159.

298. In argument, the AESO explained that it believes that extending the term of the DAT rider would achieve optimal financial outcomes for market participants in the circumstances, and would also result in the efficient use of existing transmission assets.<sup>384</sup>

299. The AESO submitted that its proposal to extend DAT Rider A1 by 20 years assumes that the original decision to grant a DAT was correct.<sup>385</sup> Further, the AESO argued:<sup>386</sup>

- The Alberta Energy and Utilities Board (the board), predecessor to the AUC, approval in Order U98125<sup>387</sup> found “a significant degree of integration between Dow and Praxair,”<sup>388</sup> consistent with the requirement in Section 4(2) of the *Hydro and Electric Energy Act* that applications for industrial system designation must support “the development of the economical supply of generation to meet the requirements of integrated industrial processes.”
- Order U98125 found in relation to the requirement under Section 4(3) of the *Hydro and Electric Energy Act* that there be common ownership of all components of the industrial operations and that a regulatory approach requiring an applicant to buy land and facilities solely to meet “certain statutory prerequisites would be unduly restrictive, not in keeping with the development of infrastructure that fosters competition, and not in the public interest.”<sup>389</sup>

300. The AESO also noted that Order U98125 found that at the time:

- Dow Chemical’s bypass option was economically, technically and physically viable.
- Dow Chemical had “consistently pursued development of the bypass over an extended period of time.”
- Dow was “... well positioned to meet its own requirements in an effective manner absent a suitable transmission bypass avoidance rate.”
- If Dow had attempted to meet its own requirements, it was “the costs of TransAlta’s underutilised transmission assets would be borne by remaining transmission system users and/or TransAlta’s shareholders.”<sup>390</sup>

301. The AESO noted that, as a consequence of these findings, the board found that the development of a suitable bypass avoidance rate for Dow Chemical was in the public interest.<sup>391</sup>

302. The AESO submitted that while Order U98125 was issued before the industrial system designation provisions of the *Hydro and Electric Energy Act* were enacted, the AESO considers that, “for all intents and purposes” Dow Chemical was granted an approval equivalent to an

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<sup>384</sup> Exhibit 22942-X0558, AESO argument, footnote 321, Exhibit 22942-X0163, Amended application, Section 6.2, paragraph 159

<sup>385</sup> Exhibit 22942-X0558, AESO argument, paragraph 182-183.

<sup>386</sup> Exhibit 22942-X0558, AESO argument, paragraph 183.

<sup>387</sup> Exhibit 22942-X0558, AESO argument, footnote 323, Decision U98125: Grid Company of Alberta Inc., Transmission Bypass Avoidance Rate, Dow Transmission Bypass (July 24, 1998) (“Order U98125”).

<sup>388</sup> Exhibit 22942-X0558, AESO argument, footnote 324, Order U98125, page 5.

<sup>389</sup> Exhibit 22942-X0558, AESO argument, footnote 325, Order U98125, page 5.

<sup>390</sup> Exhibit 22942-X0558, AESO argument, footnote 326, Order U98125, page 8.

<sup>391</sup> Exhibit 22942-X0558, AESO argument, footnote 327, Order U98125, page 8.

industrial system designation. Based on this assessment, the AESO considered that a 20-year extension of Rider A1 would be appropriate.<sup>392</sup>

### Commission findings

303. The Commission notes that Order U98125 authorized a bypass avoidance rate, known as Rider B,<sup>393</sup> for a period expiring in 2021.

304. The bypass avoidance rate arose from Dow's proposal "to transmit electricity generated onsite at Dow's Fort Saskatchewan plant complex to its onsite plants and to Praxair Canada Inc.'s (Praxair) air separation facility (ASU2), located adjacent to the Dow complex."<sup>394</sup> Further, TransAlta Energy Corporation and Air Liquide Canada Inc. proposed the construction of additional cogeneration facilities at the Dow complex. These cogeneration facilities, known as G3, would be the primary source of the incremental electricity carried by the transmission system serving Dow and ASU2.

305. The board evaluated the application for a bypass rate on the basis of four criteria:

- The bypass avoidance rate is required to respond to a credible bypass threat.
- The bypass avoidance rate must exceed the long run incremental cost of service.
- The bypass avoidance rate is no more attractive than is reasonably required to avoid duplicate facilities.
- The cost of offering the bypass avoidance rate is appropriately shared between other utility customers and the utility shareholders.<sup>395</sup>

306. In its deliberations on the legislative scheme present at the time, the board determined that:

... the EU Act sets out a legislative framework that allows for the implementation of decisions that place a greater emphasis on market forces and competition in generation. The Board considers that a narrow view of the legislation will impair the development of a framework that will implement competitive principles.<sup>396</sup>

307. This remains true today.

308. The board also determined that the capital portion of Dow Chemical's contribution \$4,656,038 was reasonable and that the annual cost of \$191,250 in operating and maintenance costs, losses and ongoing spare parts inventory, that had been arrived at through a negotiation between Dow Chemical and TransAlta, was acceptable.<sup>397</sup> The Rider B approved by the board reflected these payment obligations and a term to 2021.<sup>398</sup>

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<sup>392</sup> Exhibit 22942-X0558, AESO argument, paragraph 184.

<sup>393</sup> Rider B is now known as Rider A1.

<sup>394</sup> Decision U98125, PDF page 2.

<sup>395</sup> Decision U98125, PDF pages 2-3.

<sup>396</sup> Decision U98125, PDF page 5.

<sup>397</sup> Decision U98125, PDF pages 11-12.

<sup>398</sup> Decision U98125, PDF page 9.

309. Given this history, the Commission considers there is no basis for any presumption that the duplication avoidance tariff rider provided to Dow Chemical would be automatically extended.

310. However, the AESO also argued that Dow Chemical was effectively granted the equivalent of an industrial system designation and therefore, the bypass threat continues to be credible.

311. As stated by the Commission in Decision 23418-D01-2018:<sup>399</sup>

97. Designated industrial systems are permitted to self-supply and are exempt from the obligation to obtain electric energy through the distribution or transmission system. In accordance with Section 117(1) of the Electric Utilities Act, each industrial system designation order issued by the Commission includes a condition specifying that the electric energy produced from and consumed by the subject industrial system is exempt from the operation of the Electric Utilities Act.

98. Designated industrial systems are entitled to export the electric energy that is in excess of the industrial system's requirements because such export is expressly contemplated by subsection 4(2)(b)(ii) of the *Hydro and Electric Energy Act*. That provision states that if an electric system is designated as an industrial system, that designation must support the efficient exchange, with the interconnected electric system, of electric energy that is in excess of the industrial system's own requirements.

312. The requirements for an industrial system designation are set out in Section 4 of the *Hydro and Electric Energy Act*. The Commission does not agree that because Order U98125 was issued prior to these provisions that the operations of Dow Chemical should be considered to be the equivalent of an industrial system designation for all intents and purposes. There is no evidence on the record to demonstrate whether or not Dow Chemical would meet those requirements.

313. For all of the above reasons, the AESO's request that Rider A1 be extended for an additional 20 years to 2041 is denied. The AESO is directed to update its proposed 2018 ISO tariff to reflect this finding in its refiling.

314. The Commission's determinations in this decision in respect of the AESO's request that Rider A1 should be extended in this decision are made without prejudice to the right of Dow Chemical to make an application for a new duplication avoidance tariff to apply following the expiry of Rider A1 at the end of 2021.

## **6.6 Rate STS: Changes in GUOC rate levels**

315. The AESO proposed changes to the capacity that is used to calculate a generating unit owner's contribution (GUOC) and the method used to calculate the GUOC rate.

316. Currently the capacity used to calculate GUOC is the contract capacity under Rate STS. The AESO proposed to revise the capacity used to calculate a GUOC, as follows:<sup>400</sup>

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<sup>399</sup> Decision 23418-D01-2019: EPCOR Water Services Inc., E.L. Smith Solar Power Plant, Proceeding 23418, Applications 23418-A001 and A002, February 20, 2019.

<sup>400</sup> Exhibit 22942-X0163, Amended application, paragraph 300.



- (a) Maximum Capability of a new generating unit if only the generating unit is being added at a site; or
- (b) Maximum Capability of a new generating unit less the minimum capacity of new load being added at the same time at the same site, or is proposed to be added within 12-months of the added generation.

317. The AESO claimed the change would result in transmission connected dual-use connections (i.e., market participants with both load and generation) and distribution-connected market participants with generation having to pay “an appropriate amount of a GUOC contribution.”<sup>401</sup>

318. The AESO stated it previously calculated the GUOC rate using forecast regional peak load, future regional net generation based on signed construction commitment agreements generation surplus using the forecast regional peak load and future regional net generation, the distance between major regional load centers, and dominant path adjustments to determine the direction of generation flow.<sup>402</sup>

319. The AESO explained that when the majority of generation consisted of large fossil fuel powered generating units, knowing forecast regional (winter) peak load and future regional net generation was sufficient to approximate generation flow. With the significant wind and solar generation and generation co-located with load being added to the AIES, it is unknown how much wind and solar generation would be available when the regional winter peak load or regional summer peak load occur.<sup>403</sup>

320. The AESO proposed that using forecast flows from its engineering studies is a better method to determine a generating unit’s contribution rate. The AESO argued that using engineering studies would provide a better approximation of generation flows compared to its previously used methodology.<sup>404</sup>

321. The AESO determined the GUOC contribution rates as shown below.<sup>405</sup>

**Table 10. 2018-2020 Generating unit owner’s contribution rates**

Planning region	Current (2010-2011) rate (\$/MW)	Proposed rate (\$/MW)
Northwest	10,000	10,000
Northeast	50,000	20,000
Edmonton	32,500	30,000
Central	22,400	50,000
Calgary	10,000	40,000
South	25,000	20,000

Source: Exhibit 22942-X0163, Amended application Table 7-1 – 2018-2020 Generating unit owner’s contribution rates.

<sup>401</sup> Exhibit 22942-X0163, Amended application, paragraph 301.

<sup>402</sup> Exhibit 22942-X0163, Amended application, paragraph 302.

<sup>403</sup> Exhibit 22942-X0163, Amended application, paragraphs 303-304.

<sup>404</sup> Exhibit 22942-X0163, Amended application, paragraph 306.

<sup>405</sup> Exhibit 22942-X0163, Amended application, paragraphs 299 and 307-312.

## Commission findings

322. No objections to the AESO's proposed changes to the capacity used to calculate a GUOC, the method used to calculate the GUOC rate, or the AESO's proposed GUOC rate were submitted. Additionally, no evidence was provided to demonstrate that the AESO's proposed changes to its methodology were unjust, unreasonable or unduly preferential, arbitrary or discriminatory.

323. The Commission approves the AESO's proposed method to calculate the GUOC rate, and the AESO's GUOC rates, included in Table 10 above. However, in its refile to this decision, the Commission directs the AESO to clarify whether part (b) of the capacity used to calculate a GUOC is still required, given the Commission's decision with respect to the E.L. Smith Solar Power Plant (Decision 23418-D01-2019).

## 7 Terms and conditions

### 7.1 AESO response to Proceeding 20922 Closure Letter

#### 7.1.1 Background

324. The AESO noted in its application that the Commission had concluded that there was a need to address "whether and how customer advancement costs can be used to ensure that future system transmission facility upgrades are achieved in both a timely and an economic manner."<sup>406</sup> Following the release of Decision 3473-D02-2015, the Commission issued Bulletin 2015-15,<sup>407</sup> creating a Commission-initiated proceeding (Proceeding 20922) to address the concerns raised by the Commission in Decision 3473-D02-2015.

325. The Commission identified the following matters to be considered in Proceeding 20922:<sup>408</sup>

- System transmission project advancement costs as price signals to market participants.
- The effect of the *Transmission Regulation*, AR 86/2007, sections 15(1)(e) and (f), on classification of advancement costs.
- AESO discretion and the need to develop clear criteria when applying advancement costs in respect of system transmission projects.
- The materiality threshold for applying advancement cost provisions to system projects.
- Application of advancement cost provisions to non-radial system transmission projects.
- Application of advancement cost provisions to upgrades/enhancements of existing system transmission facilities.
- Application of system project advancement costs to generators.
- Application of system project advancement costs to distribution utilities.

<sup>406</sup> Decision 3473-D02-2015, paragraph 99, referenced at Exhibit 22942-X0163, Amended application, paragraph 170.

<sup>407</sup> Bulletin 2015-15, *Commission-initiated proceeding to address the customer advancement cost component of the Alberta Electric System Operator's tariff*, cited at Exhibit 22942-X0163, Amended application, paragraph 170.

<sup>408</sup> Bulletin 2015-15, *Commission-initiated proceeding to address the customer advancement cost component of the Alberta Electric System Operator's tariff*, October 22, 2015\.

- Time limitations on participant-related classification of system project advancement.
- The impact of system transmission project advancement cost provisions on transmission system planning and project execution.
- The adequacy of the market participation accountability mechanisms in the AESO tariff.
- Application of good electric industry practice to staged loads.

326. On March 29, 2017, the Commission issued a letter (“Closure Letter”) closing Proceeding 20922.<sup>409</sup> The Commission stated in the Closure Letter that following the release of Bulletin 2015-15, additional evidence on matters overlapping with matters under consideration in Proceeding 20922 had been filed in various Commission proceedings. Consequently, the Commission determined that the matters contemplated for Proceeding 20922 should be addressed as part of a comprehensive ISO tariff application.

327. The Commission attached Appendix 1 to the Closure Letter providing the Commission’s preliminary views regarding three principal issues as follows:

- Issue 1 – legislative framework
- Issue 2 – advanced system-related classification of radial transmission projects
- Issue 3 – load forecasting

328. The AESO addressed each of these issues in its 2018 ISO tariff application.<sup>410</sup>

### 7.1.2 Closure Letter issue 1: legislative framework

329. The AESO’s discussion of the legislative framework issues raised by the Closure Letter are found in Section 7.1.1 of its amended application.

330. Appendix 1 to the Closure Letter stated:

4. Because of the nature of the energy market in Alberta, Alberta’s electricity legislation has identified that planning for an uncongested transmission system is a key responsibility that should be allocated to the AESO. For example, sections 15(1)(e) and (f) of the *Transmission Regulation* provide direction on the allowed degree of congestion, while Section 33 of the *Electric Utilities Act* establishes the duty of the AESO to forecast the needs of Alberta and to develop plans for the transmission system reflecting the AESO’s forecast of such needs, while Section 17 requires the AESO to assess the current and future needs of market participants and plan the transmission system to meet those needs as well as to make arrangements for the expansion of and enhancement to the transmission system. Section 8 of the *Transmission Regulation* requires the AESO to consider both future load growth and anticipated generation additions for the purposes of developing its transmission system plans.

5. One interpretation of sections 15(1)(e) and (f) and Section 8(a) of the *Transmission Regulation* is that the AESO is required to ensure that it plans and arranges transmission system expansions or upgrades, in a manner that assures that any and all forecast firm load additions can be accommodated by the date requested. However, it is also possible to interpret Section 8 and Section 15 provisions as establishing different targets, one to be

<sup>409</sup> Exhibit 20922-X0023.

<sup>410</sup> Exhibit 22942-X0163, Amended application, Section 7.1.

met for construction of transmission to serve generation (Section 15 – without constraint) and another to serve forecast load (Section 8 – available in a timely manner). Because these planning restrictions affect the ability of the AESO to set and alter in-service dates, which in turn could affect the cost of achieving its congestion and planning mandates, the Commission is interested in parties exploring whether or not it is possible, desirable or feasible for the AESO to apply the less restrictive interpretation of these provisions.<sup>411</sup> [emphasis added by the AESO]

331. The AESO indicated that in addressing the legislative issues identified in Appendix 1 to the Closure Letter, and in particular those highlighted in paragraphs 4 and 5 reproduced above, the AESO examined the Commission’s findings at paragraphs 465 through 470 and paragraph 474 from Decision 2014-242,<sup>412</sup> which addressed the effects of:

- *Electric Utilities Act*, subsections 17(i) and 17(j)
- *Electric Utilities Act*, subsection 33(1)
- *Transmission Regulation*, subsections 15(1)(e) and (f)
- *Transmission Regulation*, subsection 15(2)
- *Transmission Regulation*, subsection 15(3)

332. After taking these findings into account, the AESO considered that what the Commission referred to as a “less restrictive interpretation” of provisions describing the nature of the AESO’s obligation to plan and direct the building of an “uncongested transmission system,” as discussed at paragraphs 4 and 5 of Appendix 1 to the Closure Letter, would be “possible, desirable and feasible to apply.”<sup>413</sup> Consequently, the AESO indicated that it is not required to accommodate “any and all forecast firm load additions” by the in-service date requested by a market participant. Instead, the AESO explained that its duty is to “accommodate load additions in a timely manner having regard for the safe, reliable and economic operation of the transmission system.”<sup>414</sup>

333. In addition, the AESO indicated that it considered that its duties to forecast the current and future needs of Alberta and plan and arrange for new transmission facilities as set out in subsections 17(i) and (j) and Section 33 of the *Electric Utilities Act* do not legislate any specific urgency to complete transmission system expansions and enhancements. Instead, these provisions only require the timely implementation of such projects as determined by the AESO.<sup>415</sup>

334. The AESO also discussed the guidance regarding its forecasting and planning obligations provided by sections 8 and 15 of the *Transmission Regulation*. The AESO noted in particular that Section 8(a) provides that the AESO “must anticipate future demand for electricity, generation capacity and appropriate reserves required to meet the forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capacity. Although the AESO acknowledged the Commission’s

<sup>411</sup> Exhibit 20922-X0023, Appendix 1, paragraphs 4-5, referenced at Exhibit 22942-X0163, Amended application, paragraph 172.

<sup>412</sup> Exhibit 22942-X0163, Amended application, paragraph 173.

<sup>413</sup> Exhibit 22942-X0163, Amended application, paragraph 174.

<sup>414</sup> Exhibit 22942-X0163, Amended application, paragraph 174.

<sup>415</sup> Exhibit 22942-X0163, Amended application, paragraph 175.

observation that no specific timeline is provided in Section 8(a), it recognized that it is subject to an obligation to accommodate forecast load and new generation capacity in a timely manner.

335. To assist in understanding the interplay between sections 8 and 15(1)(a), (e) and (f) of the *Transmission Regulation*, the AESO submitted that the consideration of the AESO's definitions of the terms "congestion" and "constraint," are of assistance:

**"Congestion"** occurs when the transmission system lacks the ability to transmit electricity from in merit supply to a given electricity consuming area without contravening reliability requirements. In other words, congestion arises as a result of the requirement to limit the flow of electricity on transmission lines (for the purposes of maintaining reliability to below the supply/demand balance determined by the dispatch merit order).

**"Constraint"** refers to: (i) an element of the transmission system that physically limits power flow; (ii) an operational flow limit imposed upon an element or a group of related elements to protect reliability; or (iii) a lack of transmission capacity needed to deliver electricity from existing or potential sources of supply without violating reliability criteria.<sup>416</sup>

336. The AESO explained that not all constraints lead to congestion. Further, the AESO submitted that as congestion is a term used to describe the inability to dispatch anticipated in-merit electric energy, it predominantly relates to generation and not load.

337. The AESO explained that, due to the nature of congestion, when considering the requirements for accommodating a new demand connection, the AESO is predominantly concerned with meeting the criteria in Section 15(1)(a) of the *Transmission Regulation* requiring it to plan a transmission that satisfies Alberta reliability standards.<sup>417</sup> In contrast, when planning the accommodation of new generation, the AESO explained that it is predominantly concerned with meeting the requirements of Section 15(1)(e) regarding congestion. As such, the AESO indicated that, unless the exceptions set out in sections 15(2) or (3) of the *Transmission Regulation* are justifiable, it plans the transmission system and makes arrangements for expansions or enhancements that enables the connection of generation in a manner that does not give rise to congestion that would be contrary to the criteria set out in Section 15(1)(e).

338. In conclusion, the AESO submitted that, in accordance with sections 5, 17(i), 33(1) and 34(1) of the *Electric Utilities Act* and sections 4, 8, 11 and 15 of the *Transmission Regulation*, the AESO considers that it is mandated to plan a transmission system that is flexible, forward-looking and reasonably anticipates new load and generation. However, the AESO noted that while it must reasonably anticipate and respond to forecast load and generation, it must do so not only with a view to the market participant's requested in-service date, but also with a view to fairly and economically managing the timing of system transmission facility upgrades. As such, the AESO explained that it targets the completion of its projects within a timeframe that can be completed at a reasonable cost, and in recognition of the uncertainty associated with forecast load and generation needs.

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<sup>416</sup> Exhibit 22942-X0163, Amended application, paragraph 175.

<sup>417</sup> Exhibit 22942-X0163, Amended application, paragraph 179.

## Commission findings

339. The Commission considers that the AESO's examination of the legal issues identified in issue 1 of the appendix to the Closure Letter has assisted in identifying opportunities to manage transmission system expansions with an increased focus on cost while recognizing that the in-service dates requested by market participants are one factor in the planning process and should be reasonable and balanced as against other factors.

340. The Commission agrees with the AESO's adoption of a "less restrictive" interpretation of the AESO's duty to provide a congestion free transmission system as described in Section 7.1.1 of the amended application.

341. In this regard, the Commission considers that the AESO has substantial discretion with respect to how quickly, and at what cost, it should accommodate load growth, either through the advancement of system transmission projects or connection projects initiated through system access service requests (SASRs). The Commission addresses specific provisions set out in the AESO's proposed terms and conditions arising from this determination in other parts of this decision.

342. The Commission considers that because planned generation that does not materialize within the project proponent's requested ISD or at the capacity level indicated by project proponents can result in stranded investments in transmission, the AESO should exercise all reasonable discretion available to it to ensure that the timeline and scope of generation projects are as certain as possible before the AESO commits to transmission system expansion on a project proponent's behalf.

343. The Commission notes that the AESO has proposed several provisions in its 2018 ISO tariff terms and conditions designed to improve the AESO's certainty in this regard. The Commission's findings in respect of these proposed changes follow in other parts of this decision.

344. In consideration of the foregoing, the Commission considers that the AESO has fully addressed the relevant matters described in the "Issue 1 – legislative framework" section of Appendix 1 of the Closure Letter.

### 7.1.3 Closure Letter issue 2: advanced system-related classification of radial transmission projects

345. Paragraphs 6 through 9 of Appendix 1 to the Closure Letter addressed what the AESO has described as the "in-advance system-related classification in section 8:3(3)(b)" of the ISO tariff then in effect. Paragraph 9, in particular stated:

9. As a result of the incentive effects and cost implications associated with the AESO's tariff classification of system-related costs, the Commission would like parties to address whether Section 8:3(3)(b) from the AESO's tariff should become more restrictive in terms of which transmission projects, if any, should receive in-advance system classification. The Commission also would like parties to address how the current AESO tariff practice of advancement cost designation could be improved to address the balance between the preferences for certainty among one set of market participants and the desire

to minimize the cost of transmission development among another set of market participants.<sup>418</sup> [emphasis added by the AESO]

346. The AESO noted that subsection 8:3(3) of its prior tariff was of specific concern to the Commission because it could incent a market participant to “overstate its long-term requirements, since it will not bear the full costs of such a decision.”<sup>419</sup> In addition, the AESO noted the Commission’s suggestion that, as a consequence, “the AESO could be incorporating inaccurate forecast information into its long-term plan (‘LTP’) for required transmission facilities.”<sup>420</sup>

347. The AESO responded to the Commission’s concern in subsection 7.4 of its amended application (Construction Contributions for Connection Projects). Specifically, the AESO described a number of proposed changes to provisions in its terms and conditions related to construction contributions for connection projects. The AESO’s rationale for specific changes proposed was organized within subsection 7.4 under the following headings:

- participant-related costs
- advancement costs
- avoidable construction costs
- system-related costs

### **Participant-related costs**

348. The AESO discussed the following terms and conditions changes related to the classification of costs as participant-related costs:

- a proposal to remove the terms “contiguous” and “non-contiguous” from the definition of participant-related costs, found in subsection 8:3(2) of the current ISO tariff;<sup>421</sup>
- changes in wording related to the costs associated with telecommunications in subsections 8:3(2)(e) and (f) of the current ISO tariff; and<sup>422</sup>
- changes to subsection 8:3(2)(n) of the current ISO tariff to include “future facilities” in the list of “other facilities” required to complete a market participant’s connection.<sup>423</sup>

349. A comparison of the new proposed terms with the existing tariff terms and conditions is provided in Section 7.2.5 below.

### **Advancement costs**

350. The AESO explained that it preferred the continuation of its existing approach, with updates to its cost calculation methodology, and with certain updates to the determination of system-related costs.

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<sup>418</sup> Proceeding 20922, Exhibit 20922-X0023, Appendix 1, paragraph 9.

<sup>419</sup> Proceeding 20922, Exhibit 20922-X0023, Appendix 1, paragraph 8, cited at Exhibit 22942-X0163, Amended application, paragraph 184.

<sup>420</sup> Proceeding 20922, Exhibit 20922-X0023, Appendix 1, paragraph 8, cited at Exhibit 22942-X0163, Amended application, paragraph 184.

<sup>421</sup> Exhibit 22942-X0163, Amended application, paragraphs 253-254.

<sup>422</sup> Exhibit 22942-X0163, Amended application, paragraph 255.

<sup>423</sup> Exhibit 22942-X0163, Amended application, paragraph 256.

351. The AESO explained that it had considered three high-level approaches to the determination of advancement costs to meet the objectives set out in the Closure Letter:

- Continuation of the basic method for calculating advancement costs used in the current ISO tariff.<sup>424</sup>
- Determination of advancement costs based on a \$/MW of capacity calculation.<sup>425</sup>
- Refundable charge based on the full cost of system build.<sup>426</sup>

352. The AESO submitted that its current approach sends a strong price signal and is well understood by market participants. However, the AESO proposed that the price signal should apply any time the market participant's system access service agreement requires the advancement of a system transmission project and not solely when facilities are planned to be looped within five years.

353. The AESO expressed the view that advancement occurs both when there is a plan in place to address future congestion or constraints, or where future facilities have never been contemplated to address a forecasted area constraint. Consequently, the AESO indicated that it had proposed that advancement costs apply to all demand connections that trigger the requirement for system transmission facilities to be built to accommodate a demand connection.<sup>427</sup>

354. Consequently, the AESO proposed several changes applicable only to demand connection projects that are designed to send price signals to load market participants, to provide greater certainty that connection projects will proceed, and to facilitate the timely and economic development of the transmission system.

355. Subsection 3.4(2)(a) of the proposed 2018 ISO tariff provides that, prior to its filing of a connect project needs identification document (NID) application or advancing a system transmission facility upgrade, the AESO would require that the market participant requiring the advancement of upgrade work to pay any advancement costs that may be identified.

356. Further, subsection 3.4(1) of its proposed terms and conditions describes the types of alternatives that the AESO must assess, and how the AESO must select its preferred alternative.

357. Other refinements proposed by the AESO were as follows:

- Where a system upgrade had not previously been planned, SASRs that require new system transmission facilities the assessment of advancement costs will be made on the assumption that the required system transmission upgrade is required within five years.<sup>428</sup>
- Where a system transmission project is included in an approved NID application, advancement costs will be calculated based on the actual number of months that the SASR causes the system transmission facilities to be advanced from the planned in-service date.<sup>429</sup>

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<sup>424</sup> Exhibit 22942-X0163, Amended application, paragraphs 262-269.

<sup>425</sup> Exhibit 22942-X0163, Amended application, paragraphs 270-272.

<sup>426</sup> Exhibit 22942-X0163, Amended application, paragraphs 273-276.

<sup>427</sup> Exhibit 22942-X0163, Amended application, paragraph 263.

<sup>428</sup> Exhibit 22942-X0163, Amended application, paragraph 264.

<sup>429</sup> Exhibit 22942-X0163, Amended application, paragraph 268.



### **Avoidable construction costs**

358. The current ISO tariff only provides for advancement costs to be applied to projects that are planned to be looped in five years, and calculates the advancement costs based on the cost of the AESO's planned system transmission project.<sup>430</sup>

359. The AESO submitted that ratepayers bear no responsibility for any additional costs that could occur if the load market participant chooses to maintain an in-service date if the additional costs could be avoided by delay. If the AESO identifies costs that might be avoided if targeted ISDs are delayed, the avoidable construction costs will be presented to the load market participant. If the market participant pays the avoidable construction costs in addition to the connection costs, the project will proceed as planned. However, the AESO noted that if the load market participant does not pay the avoidable construction costs, the in-service dates of both the connection project and any system transmission facilities required for the connection project may be rescheduled to a later date to avoid the additional costs.<sup>431</sup>

### **System-related costs**

360. The AESO proposed substantial changes to the ISO tariff provisions that describe system-related costs.

361. The AESO explained that it had designed its proposed changes to system-related cost provisions to reflect the general cost causation principle that if a market participant connection causes additions or upgrades that are only required for that connection and do not provide any benefit to other market participants, those costs should be attributed to that market participant receiving the benefit as participant-related costs.<sup>432</sup>

362. Substantive changes to provisions of the terms and conditions include

- removal of references to the terms “contiguous” and “non contiguous” as set out in current subsection 8:3(3);<sup>433</sup>
- removal of the current tariff's subsections 8:3(3)(a) and (b), which described system-related costs in relation to whether proposed transmission facilities are radial to the existing transmission system or create a “loop” by increasing the number of electrical paths between any two substations;<sup>434</sup>
- elimination of provisions specifying that radial connection project costs could be classified as system-related if there is a plan to loop the facilities within five years,<sup>435</sup> reflecting the AESO's expectation that provisions governing the refund of customer contributions will apply if the initial radial facilities are looped within the 20-year system access term;<sup>436</sup>

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<sup>430</sup> Exhibit 22942-X0163, Amended application, paragraph 280.

<sup>431</sup> Exhibit 22942-X0163, Amended application, paragraph 286.

<sup>432</sup> Exhibit 22942-X0163, Amended application, paragraph 287.

<sup>433</sup> Exhibit 22942-X0163, Amended application, paragraph 288.

<sup>434</sup> Exhibit 22942-X0163, Amended application, paragraphs 289-290.

<sup>435</sup> Exhibit 22942-X0163, Amended application, paragraph 290.

<sup>436</sup> Exhibit 22942-X0163, Amended application, paragraph 292.

- changes to the wording of subsection 8:3(c) to more accurately reflect the AESO's prerogative to consider its long-term planning obligations when proposing connection facilities in responses to a SASR; and<sup>437</sup>
- adding a new provision (subsection 4.2(2)(m)) to address the allocation of project costs regarding isolated communities regulated under the *Isolated Generating Units and Customer Choice Regulation* reflecting the AESO's view that the costs to connect an isolated community should be participant-related costs and should be calculated based on an economic analysis of the cost of continuing to serve the community with isolated generation compared to the cost of building the new facilities to connect a community.<sup>438</sup>

### Commission findings

363. The Commission considers that the AESO has fully addressed the relevant matters described in the "Issue 2 – advanced system-related classification of radial transmission projects" section of Appendix 1 of the Closure Letter.

364. The Commission received extensive argument from EDTI on several aspects of the classification of costs as between participant-related costs and system-related costs. The Commission has addressed these submissions and provided its findings in Section 7.2.5 costs below.

#### 7.1.4 Closure Letter issue 3: load forecasting

365. In its response to the load forecasting issue identified in Appendix 1 of the Closure Letter, the AESO noted that the primary concerns expressed by the Commission were that:

- "the AESO's forecasts of Alberta Interconnected Electric System ('AIES') energy increases have consistently been in excess of the actual increase in load that has occurred"<sup>439</sup>
- market participants may not be financially incented to provide the AESO with accurate or conservative forecast information<sup>440</sup>

366. In response to these concerns, the AESO explained that it takes several actions within its forecasting processes to ensure that its forecasts do not lead to unjustified system transmission upgrades, including:

- Considering forecasts of total load in generation in specific study areas.<sup>441</sup>
- The use of project-specific forecasts, where warranted, to supplement its study area forecasts.<sup>442</sup>

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<sup>437</sup> Exhibit 22942-X0163, Amended application, paragraph 293.

<sup>438</sup> Exhibit 22942-X0163, Amended application, paragraph 294.

<sup>439</sup> Exhibit 20922-X0023, Appendix 1 at paragraph 10, cited at Exhibit 22942-X0163, Amended application, paragraph 189.

<sup>440</sup> Exhibit 20922-X0023, Appendix 1 at paragraph 11 and 12, cited at Exhibit 22942-X0163, Amended application, paragraph 189.

<sup>441</sup> Exhibit 22942-X0163, Amended application, paragraph 190.

<sup>442</sup> Exhibit 22942-X0163, Amended application, paragraph 191.

- The use of milestones that must be met before a system transmission facility upgrade is allowed to proceed.<sup>443</sup>

367. However, it shared the Commission's concern that market participants may be incented to provide inaccurate information, which may result in the overbuilding of the transmission system. The AESO also submitted that the market participants providing inaccurate information might be able to avoid any cost consequences for doing so.<sup>444</sup>

368. To address the load forecasting issue, the AESO proposed:

- The introduction of the concept of "critical information," under which market participants are required to ensure that information regarding their projects' type (load, generation or both), the kind of generation, contract capacity, in-service dates, and location, are accurate throughout the connection process. Under this approach, market participants must amend their system access requests to update any critical information that has changed. In such event, the AESO may exercise discretion to adjust the market participant's position in its connection queue or cancel the system access request.<sup>445</sup>
- Imposing a requirement for market participants to file SASRs earlier in the connection process. Under this proposal, the AESO would only file a NID application in respect of a connection project if the SAS agreement has been executed. The AESO explained that it expected that its proposed changes to the timing of SAS agreements would ensure that requested in-service dates and requested contract capacities are certain before connection NID applications are submitted to the Commission or included in AESO forecasting and long-term planning processes.<sup>446</sup>

369. The AESO explained that the above noted proposals are reflected in specific provisions set out in Section 3 (System Access Service Requests) of its 2018 ISO tariff terms and conditions.

370. As well, the AESO provided its views in response to the Commission's request for submissions in the Closure Letter regarding whether it would be advisable to introduce a target rate of load growth as part the measures used to address incentive-related concerns.<sup>447</sup> The AESO considered that adopting a target rate of growth would be problematic, primarily because it is difficult to separate out whether a specific project requesting service is incremental to, or already included in, the AESO's overall load growth forecast.<sup>448</sup>

371. Instead, under its proposed subsection 3.4(2)(b)(ii), the AESO would have the discretion to assess a connection project by including five years of area growth in the connection studies, in an effort to determine if there is sufficient capacity to accommodate the connection. If the AESO determines there is insufficient capacity to accommodate the market participant's SASR, the market participant will be offered the option of a reduced contract capacity amount, thereby

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<sup>443</sup> Exhibit 22942-X0163, Amended application, paragraph 192.

<sup>444</sup> Exhibit 22942-X0163, Amended application, paragraph 193.

<sup>445</sup> Exhibit 22942-X0163, Amended application, paragraph 193a.

<sup>446</sup> Exhibit 22942-X0163, Amended application, paragraph 193b.

<sup>447</sup> Proceeding 20922, Exhibit 20922-X0023, Appendix 1, paragraph 13.

<sup>448</sup> Exhibit 22942-X0163, Amended application, paragraph 198.

allowing the AESO to reliably plan and operate the transmission system without having to build or enhance system transmission facilities.<sup>449</sup>

### **Commission findings**

372. The Commission considers that the AESO has fully addressed the relevant matters described in the “Issue 3 – load forecasting” section of Appendix 1 of the Closure Letter.

373. The Commission accepts the AESO’s explanation that always adopting a target rate of growth would be difficult due to the complexity of separating out whether a specific project requesting service is incremental to, or already included in, the AESO’s overall load growth forecast. Instead, allowing the AESO the discretion to consider five years of load growth in the connection studies is a reasonable approach because it corresponds to the AESO’s planning window.

374. The Commission has addressed and provided its findings in response to the AESO’s proposals to require critical information in conjunction with SASRs in Section 7.2.3 of this decision.

375. The Commission has addressed and provided its findings in response to the AESO’s proposal to require payments of (GUOC) at the time of generation market participant SASRs in Section 7.2.4.

## **7.2 Terms and conditions changes arising from the Closure Letter**

### **7.2.1 Terms and conditions: ID 20922 Closure Letter issues: AESO discretion to make contract capacity adjustments**

376. The AESO proposed the following change to its terms and conditions for service:

**5.2(1)** A market participant, the ISO or the legal owner of a transmission facility may initiate a review of the construction contribution that the ISO had previously determined for a connection project.

**5.2(2)** If the ISO determines that the contract capacity amount in a System Access Service Agreement for Rate DTS or Rate STS previously determined by the ISO in respect of subsections 3.6(2) and (3) of the ISO tariff, System Access Service Request, does not reflect the actual flows, the ISO may adjust the contract capacity to reflect such actual flows and the market participant must pay any recalculated amounts for any construction contribution in accordance with this section 5 of the ISO tariff, Changes to System Access Service, and any contribution for a generating unit or aggregated generating facility calculated in accordance with section 7 of the ISO tariff, *Generating Unit Owner’s Contribution*, as applicable.

**5.2(3)** The ISO must review a construction contribution determination and may determine a construction contribution adjustment is required when:

- (a) a market participant materially increases or decreases contract capacity or investment term or terminates system access service, prior to the expiry of the investment term for a connection project;

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<sup>449</sup> Exhibit 22942-X0163, paragraph 198.

(b) one or more additional market participants use facilities originally installed for an existing market participant, resulting in sharing of facilities as provided for in subsection 5.5 below;

(c) connection project costs previously classified as system-related are reclassified as participant-related to meet changes in market participant requirements;

(d) connection project costs previously classified as participant-related are reclassified as system-related;

(e) a material error in the original construction contribution is identified; or

(f) the estimated or actual cost of the connection project materially varies from the original estimate.

**5.2(4)** The ISO must determine a construction contribution under the provisions of section 4 of the ISO tariff, Classification and Allocation of Connection Projects Costs, rather than this section 5, if an increase in contract capacity requires the construction of transmission facilities at an existing point of delivery or point of supply.

**5.2(5)** The ISO must not make an adjustment to a construction contribution more than 20 years after commercial operation of a connection project.<sup>450</sup>

377. The AESO argued that the proposed changes to its terms and conditions were in response to the Commission's closure letter<sup>451</sup> from Proceeding 20922<sup>452</sup> and

... intended to address the Commission's interest in a broader examination of incentives induced by the design of the ISO tariff to influence the costs of transmission development in Alberta. The measures are also intended to strengthen the financial and contractual incentives that can be provided to market participants through the ISO tariff in order to ensure that the AESO receives more accurate information for forecasting, transmission system planning, and tariff rate design purposes ...<sup>453</sup> [footnote removed]

378. The changes to the terms and conditions included "discretion for the AESO to adjust existing contract capacities in the event they differ materially from actual flows to or from the transmission system."

379. Subsection 5.5(2) garnered interest from several proceeding participants.

380. The Commission has summarized subsection 5.2(2) of the proposed 2018 ISO tariff:

The AESO is provided with discretion to adjust existing contract capacities under Rate DTS (Demand Transmission Service) or Rate STS (Supply Transmission Service), in the event that the AESO determines such contract capacity does not reflect the actual flows to or from the transmission system.

<sup>450</sup> Exhibit 22942-X0014.03, Appendix R, ISO Tariff – Section 5 Changes to System Access Service, PDF page 69.

<sup>451</sup> Exhibit 22942-X0009, Appendix M. The closure letter was issued March 29, 2017.

<sup>452</sup> Proceeding 20922, the Commission-initiated proceeding to address the customer advancement cost component of the AESO's tariff.

<sup>453</sup> Exhibit 22942-X0558, AESO final argument, paragraph 13.

Its effect:

Where such an adjustment is made, the market participant would be required to pay any recalculated amounts for any construction contribution in accordance with proposed Section 5 of the 2018 ISO tariff, Changes to System Access Service, and any contribution for generating facility calculated in accordance with proposed Section 7 of the 2018 ISO tariff, Generating Unit Owner's Contribution.

Its purpose:

Subsection 5.2(2) would assist the AESO in obtaining accurate and consistent information from existing market participants and help to ensure that other tariff provisions can be properly applied, for example, provisions related to the payment in lieu of notice ("PILON"), avoidable construction costs, advancement costs, and the allocation of interconnection costs between DTS and STS using the AESO's existing substation fraction methodology.<sup>454</sup> [footnotes removed]

381. The AESO acknowledged that while it engaged with stakeholders about its critical requirements for critical information, it did not consult with stakeholders on the specific wording for subsection 5.2(2) prior to its introduction into the amended application.

382. The AESO provided the following guidelines as to how it would apply its discretion in terms of subsection 5.2(2):

- When the AESO observes a deviation greater than 10 per cent from the contract capacity under Rate DTS or Rate STS.<sup>455</sup>
- Where a market participant can show to the satisfaction of the AESO that it has a current need for the excess capacity (as could be the case with self-supply sites seeking a reliable source of supply in the event the source of self-supply is interrupted, or for operational requirements).
- Where a market participant requires a staged load increase over a period of time considered reasonable by the AESO.
- Prior to a downward adjustment to any DTS contract capacity, the AESO would discuss the issue with the market participant.<sup>456</sup>

383. The AESO did agree with the suggestion of a number of parties that an information document, to provide market participants with an expectation of how the AESO would exercise its discretion under proposed subsection 5.2(2), would be helpful.<sup>457</sup>

384. ATCO Electric submitted that it and other parties would be directly impacted by this proposed revision and noted that the AESO did not consult sufficiently with affected parties nor did it communicate its proposed approach to revising contract capacities. ATCO added that material changes to existing terms and conditions, affecting market participants, should only

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<sup>454</sup> Exhibit 22942-X0558, AESO final argument, paragraph 22.

<sup>455</sup> Exhibit 22942-X0312.01, AESO-DEVON-2018NOV01-001(b)(ii), PDF page 2.

<sup>456</sup> Exhibit 22942-X0312.01, AESO-DEVON-2018NOV01-001(c), PDF pages 2-3.

<sup>457</sup> Exhibit 22942-X0558, AESO final argument, paragraph 113.

occur after affected parties have had input into such changes and after adequate consultation has been completed by the AESO.<sup>458</sup>

385. ATCO Electric was concerned that the guidelines proffered by the AESO in response to AESO-DEVON-2018NOV01-001(b)(ii), and in its rebuttal evidence,<sup>459</sup> were not reflected in the proposed wording in the terms and conditions.

386. ATCO Electric argued that the proposed change effectively delinks DTS contract capacities from the AESO's investment policy. In ATCO's case, the short-term impact of the AESO's proposed change to its Terms and Conditions is an inappropriate transfer of transmission system upgrade costs to the DFO and puts upward pressure on distribution rates.<sup>460</sup>

387. ATCO Electric added several more concerns including:

- The AESO's proposal would also deprive ATCO Electric's end-use customers of available AESO investment to help offset upgrade costs.
- The AESO has not clarified how it would deal with increases in contract capacity.
- The AESO's proposed changes simply do not address circumstances where a contract reduction is directed; but is followed by a subsequent increase due to the normal variations that are historically experienced at certain locations.<sup>461</sup>

388. Access Pipeline Inc. noted its concerns as follows:

- Subsection 5.2(2) would provide the AESO with broad discretionary capability to determine how, when, where and why to adjust contract capacity levels. The AESO's proposal would apply to both existing and future System Access Service (SAS) Agreements on an ongoing basis.<sup>462</sup>
- Subsection 5.2(2) creates significant uncertainty in both the terms under which the service is supplied by the AESO and the ultimate cost of the particular service a market participant receives from the AESO.<sup>463</sup>
- Access Pipeline does not agree with the implementation of a tariff with terms that give the AESO ability to supersede the customer's judgment regarding contract level and unilaterally change agreements that were entered into in good faith and based on sound commercial reasons. Determination of desired contract level has been and should remain a customer prerogative; customers rely on contract levels to plan and operate their businesses.<sup>464</sup>

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<sup>458</sup> Exhibit 22942-X0553, ATCO final argument, paragraph 46.

<sup>459</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraphs 71-76.

<sup>460</sup> Exhibit 22942-X0553, ATCO final argument, paragraph 51.

<sup>461</sup> Exhibit 22942-X0553, ATCO final argument, paragraphs 52-57.

<sup>462</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 4.

<sup>463</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 5.

<sup>464</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 7.

- The AESO's proposed change goes to the very object of the contract rather than the terms and conditions of the SAS Agreement.<sup>465</sup>
- Approval of subsection 5.2(2) is not required for the AESO to offer the PILON waiver to market participants. If the AESO is concerned with over-contracting and building unnecessary transmission, then the use of a PILON waiver seems like an appropriate mechanism to deal with this issue and it can be immediately utilized within the existing approved tariff.<sup>466</sup>
- No direct evidence was provided on how the proposed provision would work, nor were any studies submitted on whether the proposal would be effective in addressing the Commission's concerns. Access Pipeline submitted that the AESO only provided:
  - limited rebuttal evidence in response to concerns raised by others in this proceeding;
  - details about how the proposed provision was to work in an IR response, where these details first emerged; and
  - further details about how the proposed provision was to work in cross-examination, where these details continued to emerge and evolve.<sup>467</sup>

389. Access Pipeline recommended that the AESO not be granted the sweeping powers of subsection 5.2(2) of its terms and conditions.

390. DUC et al. recommended that the Commission not approve subsection 5.2(2) and provided the following in support of its position:

- Dual-use customers choose DTS and/or STS contract capacities based on the ISO tariff provisions that will cause capital and operating costs to be incurred based upon their risk tolerance.
- For some dual-use customers, the electricity they consume from the transmission grid is infrequent and often at demand levels significantly below their DTS contract capacity. These customers have made a choice between connection costs, DTS tariff costs and the risk of being curtailed. Since DTS contract capacity is used to determine Billing Capacity, a dual-use customer may pay for Regional and POD transmission capacity for years that are never utilized.
- What may appear to be a DTS contract capacity for a dual-use customer that is too high, may in fact be appropriate and based on a rational cost / risk evaluation.
- To alter a contract term at any time, presumably without notice, and impose new costs on a customer, is both commercially unreasonable and unprecedented in Alberta.
- Subsection 5.2(2) wording does not provide for consultation or negotiation.
- The regulatory compact between the AESO and its customers is that when a customer connects to the transmission grid they elect DTS and/or STS contract capacities based on their operational needs, the quantum of investment provided

<sup>465</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 10.

<sup>466</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 35.

<sup>467</sup> Exhibit 22942-X0552, Access Pipeline final argument, paragraph 38.



and the customer capital contribution required to obtain service. Providing the AESO with the ability to alter these contract values is retroactive ratemaking.

- Imposing new tariff costs to consumers to improve planning is unjust and unreasonable.<sup>468</sup> [footnotes removed]

391. Fortis was conditionally supportive of subsection 5.2(2), but suggested that the AESO's development of an information document outlining a consistent practice for the establishment of appropriate DTS and STS contract levels would provide additional and much needed clarity for market participants.<sup>469</sup>

392. In reply, DUC et al. stated that an information document does not require AUC approval and is not subject to regulatory scrutiny. DUC et al. submitted that altering the terms of a DTS or STS contract, as part of the ISO tariff, requires Commission review and approval.<sup>470</sup>

393. In response to the argument from Fortis, DUC et al. agreed that DTS contract capacities should reflect load capacity at the in-service date and would be more supportive if the AESO was requesting the ability to adjust DTS and/or STS contract capacities within a reasonable period of time after an initial connection or upgrade. Further, DUC et al. was of the view that the AESO's requested discretion goes beyond making adjustments to initial contract capacity levels. However, the AESO's request for discretion to alter contract capacities at any time for the purpose of better planning information is in DUC et al.'s view not cost-based and does not follow cost causation.<sup>471</sup>

394. ENMAX replied stating subsection 5.2(2) is a blunt instrument that is ill-suited for the AESO's stated objective of trying to obtain good and accurate information from market participants; and if the AESO believes it needs an enforcement mechanism to allow it to adjust contract demands for customers who are intentionally misrepresenting their demand requirements, it should propose one. Finally, ENMAX submitted that processes related to these adjustments should be in authoritative documents and not information documents.<sup>472</sup>

395. ATCO Electric submitted that the AESO's proposed amendment is not well thought through and should not be implemented. Further, this change would require specific criteria that would be consistently applied and which should be known to market participants before they are confronted with a circumstance where their contracted capacities would be unilaterally changed by the AESO. ATCO Electric submitted that granting one party (the AESO) to a contract the ability to unilaterally change such an agreement should not be done lightly by the Commission.<sup>473</sup>

396. ATCO Electric expressed concern that the AESO's proposed amendment delinks DTS contract capacities from the AESO investment policy. This action transfers transmission system upgrade costs to the DFO and results in upward pressure on distribution rates.<sup>474</sup>

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<sup>468</sup> Exhibit 22942-X0543, DUC et al., final argument, PDF pages 35-36.

<sup>469</sup> Exhibit 22942-X0559, Fortis reply argument, paragraph 49.

<sup>470</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF page 8.

<sup>471</sup> Exhibit 22942-X0563, DUC et al., reply argument, PDF pages 8-9.

<sup>472</sup> Exhibit 22942-X0571, ENMAX reply argument, paragraph 5.

<sup>473</sup> Exhibit 22942-X0572, AE reply argument, paragraphs 38-39.

<sup>474</sup> Exhibit 22942-X0572, AE reply argument, paragraph 41.

397. ATCO Electric noted it could suffer potential harm through deprivation of the AESO investment for substation upgrades where overtime load may grow.<sup>475</sup>

398. Although the AESO has stated that PILON waiver provisions protect ATCO Electric from downward adjustments of contract capacities, ATCO Electric noted that the PILON waiver provisions are restrictive and would not realistically apply to the AESO-imposed reductions on contract capacity.<sup>476</sup>

399. ATCO Electric argued that the development of an information document to explain how the AESO would apply the proposed subsection 5.2(2), provides no assurances that such an information document will address the harm to ATCO Electric and its customers caused by the imposition of PILONs and additional contributions in the case of the AESO unilaterally reducing contract capacity, or the loss of available investment in the case of the AESO unilaterally increasing contract capacity.<sup>477</sup>

400. Fortis replied that the AESO should be required to issue and consult on an information document setting out how proper DTS and STS levels are established, if subsection 5.2(2) of the AESO's terms and conditions is approved.<sup>478</sup>

401. The AESO agreed with DUC et al. that customers elect DTS and/or STS based on their operational needs, the quantum of investment provided and the customer capital contribution with the proviso that DTS and STS contract capacities should not be used for reserving contract capacity.<sup>479</sup>

402. The AESO rejected DUC et al.'s claim that subsection 5.2(2) is retroactive ratemaking. The AESO submitted that if approved, subsection 5.2(2) would be part of the AESO tariff and would only authorize the AESO to adjust contracts on a go-forward basis.<sup>480</sup>

403. Regarding PILON charges, the AESO stated that an increase in DTS contract capacity would not trigger any PILON charge under the current or proposed ISO tariff. A PILON is only payable by a load market participant if insufficient notice of a reduction in DTS consumption is provided, in accordance with subsection 3 of Section 9 of the current ISO tariff and proposed Section 5.3 of the 2018 ISO tariff. The AESO also noted that there are PILON waiver provisions that could also apply. If a PILON is required, the AESO considers it to be appropriate for the payment to be based on an accurate DTS contract capacity that is reflective of the actual consumption and any excess capacity that is legitimately required by the market participant.<sup>481</sup>

404. In response to comments regarding consultation on subsection 5.2(2), the AESO did consult with stakeholders on the AESO's proposed provision regarding critical information requirements, that it views subsection 5.2(2) as a complement to the critical information

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<sup>475</sup> Exhibit 22942-X0572, AE reply argument, paragraph 42.

<sup>476</sup> Exhibit 22942-X0572, AE reply argument, paragraph 44.

<sup>477</sup> Exhibit 22942-X0572, ATCO Electric reply argument, paragraph 44.

<sup>478</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 46.

<sup>479</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 36.

<sup>480</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 37.

<sup>481</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 38.

requirements, and that any potential adjustment of contract capacity would require a case-by-case assessment and consultation with the market participant at issue.<sup>482</sup>

405. The AESO countered ENMAX's comments regarding an enforcement mechanism by noting that in the event of a dispute regarding any exercise of the AESO's discretion under subsection 5.2(2), a market participant can pursue informal and formal dispute resolution in accordance with Section 103.2 of the ISO rules, *Dispute Resolution*. Further, Section 12.4(1) of the proposed 2018 ISO tariff sets out customer contact (notice) requirements.<sup>483</sup>

406. In response to Access Pipeline, the AESO emphasized its statutory duties, including the AESO's duty under Section 29 of the *Electric Utilities Act* "to provide system access service on the transmission system in a manner that gives market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so," and under Section 17(h) of the *Electric Utilities Act*, "to direct the safe, reliable and economic operation of the interconnected electric system." The AESO submitted that from those provisions, it is clear that the AESO is not obliged to provide system access service in any manner that a customer requests, or in a manner that is not consistent with the safe, reliable and economic operation of the interconnected electric system. The AESO can only provide system access service in a manner that is consistent with its duties under the *Electric Utilities Act*. The AESO suggested that Access Pipeline is asking the AESO to ignore the *Electric Utilities Act* and treat SAS agreements as purely commercial arrangements that can be entered into without regard for the AESO's duties under the *Electric Utilities Act*. The AESO proposed subsection 5.2(2) in order to ensure that a "reasonable opportunity" continues to be provided to market participants, while also ensuring that the AESO can plan the transmission system in the most efficient manner possible.<sup>484</sup>

407. The AESO postulated that it appears that Access believes that, notwithstanding materially reduced flows, market participants are entitled to reserve capacity on the transmission system for an indeterminate future need. The AESO considers this position to be at odds with the Commission's finding in Decision 2014-242<sup>485</sup> that there are neither explicit nor implicit transmission rights in Alberta.<sup>486</sup>

408. In response to ATCO Electric, the AESO replied that any contract adjustment required as a result of subsection 5.2(2) would result in a recalculation of construction contribution in accordance with the ISO tariff. An adjustment under subsection 5.2(2), if determined by the AESO to be appropriate, would ensure that accurate contribution, investment, GUOC, substation fraction for Rate DTS billing calculations and other amounts are achieved.<sup>487</sup>

### Commission findings

409. The Commission agrees with the AESO's submission that DTS and STS contract capacities should not be used for reserving contract capacity and that there are neither explicit nor implicit transmission rights and access to the transmission system in Alberta.

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<sup>482</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 39.

<sup>483</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 41.

<sup>484</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 42.

<sup>485</sup> Decision 2014-242, paragraphs 761-763.

<sup>486</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 44.

<sup>487</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 45.

410. The Commission accepts that contracted DTS and STS levels should correlate to the actual/expected operational levels and not be overstated to maximize AESO investment.

411. The Commission also accepts that the purpose of subsection 5.2(2) of the proposed tariff is to assist the AESO in obtaining accurate and consistent information from existing market participants and help to ensure that other tariff provisions can be properly applied.

412. The Commission dismisses parties' arguments that it should not consider the AESO's amendment on the basis that the AESO did not engage in sufficient consultation prior to filing its tariff amendment.

413. In Decision 2014-242, the Commission provided its findings regarding when the AESO is required to engage in consultations.<sup>488</sup> Section 3 of the *Transmission Regulation* requires the AESO to consult with market participants who are "likely to be directly affected" by the AESO's board's approval of the ISO's own administrative costs, costs for provision of ancillary services or the costs of transmission line losses. The AESO's proposed discretion to make contract capacity adjustments does not fall within any of these categories. Further, in the event that the AESO chooses to consult on an issue, Section 2 of the *Transmission Regulation* provides the AESO with the discretion to determine how that consultation will proceed. Consequently, the AESO has not contravened any legislative provision to consult on this matter.

414. Further, regardless of any consultation process that was conducted by the AESO on this matter, the Commission has provided all parties who consider themselves to be affected by the AESO's proposed amendment an adequate forum to present their positions, evidence and argument on this matter.

415. Through the evidentiary portion of this process, the AESO stated that prior to a downward adjustment to any DTS contract capacity, the AESO would discuss the issue with the market participant, and that the following situations would merit consideration when applying its discretion with respect to subsection 5.2(2):

- When the AESO observes a deviation greater than 10 per cent from the contract capacity under Rate DTS or Rate STS;
- Where a market participant can show to the satisfaction of the AESO that it has a current need for the excess capacity (as could be the case with self-supply sites seeking a reliable source of supply in the event the source of self-supply is interrupted, or for operational requirements); and
- Where a market participant requires a staged load increase over a period of time considered reasonable by the AESO

416. The Commission directs the AESO to amend subsection 5.2(2) to include wording that this subsection will not apply to deviations below 10 per cent, that any proposed adjustments by the AESO must first be discussed with the market participant, and that a direct reference to the sections of the dispute resolution process that can be utilized by market participants regarding any disputes that may arise under this provision of the terms and conditions be provided.

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<sup>488</sup> Decision 2014-242, paragraph 68.

417. Further, the Commission encourages the AESO to develop a consultation process to establish further criteria and guidelines as to how subsection 5.2(2) will be applied. For example, in the paragraph 92, for the second bullet, the AESO is to provide further guidance as to what would satisfy the AESO in terms of need for excess capacity. In that same paragraph, for the third bullet, further guidance is required to explain what the AESO considers to be reasonable timing for a staged load increase. The consultation process is also to include other matters regarding subsection 5.2(2) that may be brought forward by market participants.

418. To clarify, the Commission is not looking for detailed rules regarding the application of this subsection. Rather, if following stakeholder engagement, further amendments to subsection 5.2(2) are determined to be beneficial and consensus can be made in an information document, then the AESO is directed to include those amendments in the information document as part of its next AESO tariff application.

419. Subject to the above directions, the Commission approves subsection 5.2(2) of the AESO's terms and conditions.

## **7.2.2 Terms and conditions: ID 20922 Closure Letter issues: ISO preferred alternative – subsection 3.4(1)**

420. As discussed above in Section 7.1, the AESO proposed to address the Commission's concerns with its subsection 8:3(3)(b) tariff provision that may result in a connecting market participant having an incentive to overstate its long-term requirements, thereby resulting in inaccurate forecast information being incorporated into the AESO's long-term plan through the imposition of advancement cost signals in various provisions of its proposed tariff terms and conditions.

421. One such response is the AESO's proposed subsection 3.4(1):

### **ISO Preferred Alternative**

3.4(1) If the construction of transmission facilities is required for a connection project, the ISO must determine how to respond to the system access service request, and select the ISO's preferred connection alternative taking into account relevant factors including the following:

- (a) the overall long-term cost of a connection alternative, including, as applicable:
  - (i) if the system access service request was submitted by the legal owner of an electric distribution system, all distribution costs;
  - (ii) costs classified as participant-related in accordance with subsection 4.2(2) of the ISO tariff, Classification and Allocation of Connection Projects Costs;
  - (iii) costs associated with system transmission facilities, being transmission facilities that the ISO determines will benefit many market participants, identified in subsections 3.4(1)(b) and (c) below; and
  - (iv) all other transmission costs (including the costs of any non-wires solutions) not included in subsections 3.4(1)(a)(i), (ii) and (iii) above required for the connection;

- (b) if the system access service request is for Rate DTS, the effect of a connection alternative on the transmission system, including all transmission constraints, under Category A and Category B conditions as described in reliability standards, as a result of the connection alternative, and the system transmission facilities required to resolve the transmission constraints; and
  - (c) if the system access service request is for Rate STS, the effect of a connection alternative on the transmission system, including:
    - (i) all transmission constraints under Category A conditions as described in reliability standards, that are a result of the connection alternative, and the system transmission facilities required to resolve the transmission constraints;
    - (ii) all transmission constraints under Category B conditions as described in reliability standards, that are a result of the connection alternative, the system transmission facilities required to operationally manage the transmission constraints, and the operating procedures required to manage the Category B transmission constraints; and
    - (iii) all transmission constraints under Category B conditions as described in reliability standards, that are a result of the connection alternative and cannot be managed operationally, then the system transmission facilities required to resolve the transmission constraints.
- and;
- (d) if the system access service request is for both Rate DTS and Rate STS, the ISO must consider the effect on the transmission system separately for Rate DTS and Rate STS.

422. In its evidence, AltaLink submitted that, although the AESO states in the application<sup>489</sup> that assessments of overall long-term costs within the context of the determination of the ISO preferred option should take into account “all relevant current and projected efficiency, timing, land use, safety, environmental, and other applicable considerations,” and that it expected that these matters would be addressed by the TFO in TFO proposals and estimates, it was not consulted on these requirements.<sup>490</sup>

423. AltaLink explained that because “overall long term cost” is not an industry defined term, there can be significant differences in the estimates prepared by different parties arising from the use of different assumptions. Therefore, further parameters are required to create meaningful estimates of life cycle costs for connection project alternatives. As well, because preliminary estimates are generally performed at a very high level, and subject to wide variation (i.e., +30 per cent / – 30 per cent at the proposal to provide service stage), there is often very little information regarding siting, engineering, land owner consultation and constraints, or environmental features available. Given this, AltaLink submitted that it is unreasonable to expect a TFO to create an estimate that contains the life cycle cost of all immediate and future transmission and distribution facilities that are impacted by the alternative and which takes into account “all relevant current

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<sup>489</sup> Exhibit 22942-X0163, Amended application, paragraph 222, cited at paragraph 170 of Exhibit 22942-X0342, AltaLink rebuttal evidence.

<sup>490</sup> Exhibit 22942-X0342, AltaLink rebuttal evidence, paragraph 172.

and projected efficiency, timing, land use, safety, environmental, and other applicable considerations” with no further guidance or parameters as to what is expected to be included in the estimate.<sup>491</sup>

424. AltaLink noted that it has prepared estimates in the past using the replacement cost new (RCN) value of used equipment that may be installed in projects. However, it expressed concern that replacement cost new estimates could be different on the basis of the different service lives of distribution and transmission assets. AltaLink submitted that the AESO’s response to IRs<sup>492</sup> has heightened its concern over the conflict between wide variation of RCN estimates that may reflect different assumptions as between DFOs and TFOs, and the fact that the proposed language of subsection 3.4(1), which would be in an authoritative document (i.e., the ISO tariff), includes the requirement to take into account the “overall long term cost of a connection alternative.”

425. AltaLink added that the AESO tariff is an authoritative document therefore failure to follow it would be subject to Market Surveillance Administrator penalties. Given this, AltaLink submitted that without further detail and examination of what is expected by the AESO in relation to “over all long-term cost”, the TFOs requirement to determine the ISO preferred alternative should be removed from the AESO Tariff.<sup>493</sup>

426. The AESO responded in its rebuttal evidence that AltaLink has misconstrued the intention behind its proposed subsection 3.4(1). The AESO explained that this provision permits the AESO to request RCN estimates to compare with the overall long-term costs of alternatives. Further, where two alternatives are close under RCN estimates, the AESO would be permitted to request more detailed estimates to compare the overall long-term costs.

427. The AESO noted that in its response to AESO-AML-2018NOV01-003(e),<sup>494</sup> it explained that connection alternatives are normally explored as part of Need for Development reports or Distribution Deficiency reports submitted by a DFO, and are prepared at a very high level. In most cases, the AESO rejects alternatives immediately due to materially higher costs. However, when the cost estimates for two alternatives are very close, it will request that the DFO or TFO provide further detail. The AESO explained that it would request further information only where alternatives are comparable in their high-level cost estimates.

428. In its argument, the AESO submitted that because no questions were asked about section 3.4(1) during the oral hearing, it expected that the clarifications it had provided in its rebuttal evidence had addressed AltaLink’s concerns.<sup>495</sup>

429. In its argument, AltaLink reiterated the concerns expressed in its intervenor evidence with respect to the vagueness of the AESO’s requirement to take into account the overall long-term cost of alternatives, and submitted that it disagreed with the AESO’s suggestion that it expected that instances where two RCN estimates are close, requiring additional review, would be rare.<sup>496</sup> AltaLink also expressed concern about inconsistencies between the authoritative

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<sup>491</sup> Exhibit 22942-X0342, AltaLink rebuttal evidence, paragraph 174.

<sup>492</sup> AESO-AML-2018NOV01-003(f), also AESO-AML-2018NOV01-004(a)(i).

<sup>493</sup> Exhibit 22942-X0342, AltaLink rebuttal evidence, paragraph 180.

<sup>494</sup> Exhibit 22942-X0256, PDF page 8, cited at Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 63.

<sup>495</sup> Exhibit 22942-X0558, AESO argument, paragraph 49.

<sup>496</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 277.

language of Section 3.4(1) and the AESO's rebuttal evidence. In this regard, AltaLink noted that as the ISO tariff is an authoritative document, it is crucial that the requirements of the tariff are clear, and accurately describe the process the AESO plans to follow.<sup>497</sup>

430. AltaLink argued that because the AESO's expectation that RCN estimates would be used for the determination of the overall long-term cost of alternatives is not reflected in the language of subsection 3.4(1), the AESO should clearly state this in the tariff and that subsection 3.4(1) should not be approved and should be removed from the proposed ISO tariff.<sup>498</sup> In addition, AltaLink submitted that the AESO should be directed to undertake further consultation regarding the process for evaluating the preferred solution for a SASR.<sup>499</sup>

431. CPC also argued that the AESO's proposed changes to process for SASRs should not be approved as filed. It submitted that the proposed changes lack critical and sufficient details and clarity with respect to definitions of key assessment criteria, and the intended application and weighing of such criteria. Therefore, it considered the AESO's proposed changes to be deficient.<sup>500</sup>

432. In response to a CPC IR seeking guidance on how the AESO would quantify costs in relation to considerations such as "current and projected efficiency," timing, land use, safety and environmental considerations, the AESO stated as follows:

The cited examples (i.e., current and projected efficiency, timing, land use, safety, environmental) would be addressed by the applicable transmission facility owner ("TFO") through the land impact assessment or cost estimate that the TFO prepares in response to a NID assistance direction that the AESO would issue to the TFO under section 39 of the EUA or a request issued by the AESO under Section 504.5 of the ISO rules, Service Proposals and Cost Estimating.<sup>501</sup>

433. In the event that the Commission approved the AESO's proposed changes, CPC submitted that such approval should be conditional upon directions to the AESO to provide clear methods for quantifying costs, and conditional upon confirmation as to how its proposed additional assessment connection alternatives will be considered and weighed relative to cost-based metrics.<sup>502</sup>

434. In its reply, the AESO submitted that it is notable CPC and AltaLink were the only parties to have raised issues with the proposed subsection 3.4(1) of the 2018 ISO tariff,<sup>503</sup> yet neither party chose to question the AESO witness panel on this subject after reviewing the AESO's rebuttal evidence in and IR responses.<sup>504</sup>

435. In response to the submissions of both CPC and AltaLink that the AESO needs to provide additional criteria with respect to the overall long-term cost of a connection alternative, the AESO submits that no further set of criteria is necessary nor is there a need to revise its proposed

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<sup>497</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 268.

<sup>498</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 28(d).

<sup>499</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 28(e).

<sup>500</sup> Exhibit 22942-X0545, CPC argument, paragraph 8.

<sup>501</sup> Exhibit 22942-X0278, AESO-CPC-2018NOV01-003, page 3.

<sup>502</sup> Exhibit 22942-X0545, CPC argument, paragraph 4(a).

<sup>503</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 18.

<sup>504</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 14.



subsection 3.4(1)(a). This is because the language used in subsection 3.4(1)(a) incorporates the AESO's intention that RCN estimates will be prepared at a high level initially, and that a more detailed estimate may be prepared, when necessary.<sup>505</sup>

### Commission findings

436. It is important that the ISO tariff clearly communicate to market participants who request more expensive solutions than a viable but substantially less expensive solution, that they should be required to pay a cost differential. Given this, the Commission considers there is a need to include a provision setting out the AESO's obligation to select the ISO preferred solution, as determined by the AESO, within the tariff.

437. While the Commission accepts that there may be some uncertainty as to how determinations in respect of subsection 3.4(1) will be applied in specific circumstances, given the importance that the Commission places on sending an economic signal to market participants that create costs that would otherwise be paid by other ratepayers that cannot control those costs, the Commission does not agree with AltaLink's recommendation that subsection 3.4(1) be completely removed from the tariff until the degree of certainty that AltaLink considers it requires has been achieved.

438. The Commission also notes that CPC filed no intervenor evidence, yet makes an even broader request that the Commission not approve all of the changes to SASR provisions that the AESO described at paragraph 204 of the amended application.<sup>506</sup>

439. All parties to this proceeding who consider themselves to be affected by the AESO's proposed subsection 3.4(1) amendment have been provided with an adequate forum to present their positions, evidence and argument regarding this proposed change. In this regard, these parties could have provided their proposed revisions to the amendment for consideration.

440. Accordingly, the Commission denies AltaLink's request for the Commission to direct the AESO to remove subsection 3.4(1) from the 2018 ISO tariff. CPC's request is also denied.

441. Regarding concerns raised about the lack of clarity as to how "overall long term cost" as set out in subsection 3.4(1) will be determined, the Commission accepts the AESO's evidence in its response to AESO-AML-2018NOV01-003(f)<sup>507</sup> in which the AESO stated that it "expects that cost estimates prepared on a 'replacement cost new' basis will typically be sufficient for purposes of distinguishing between connection alternatives" and that it will "request further information only when determining the lowest cost alternative, where the alternatives are comparable in high level cost estimates."

442. Although the Commission considers that the AESO should have discretion with respect to subsection 3.4(1) and that the AESO will exercise its discretion reasonably, in light of the concerns of parties in this proceeding, additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.4(1). Accordingly, the Commission directs the AESO to work with market participants for the purposes of addressing any concerns

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<sup>505</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 15

<sup>506</sup> Exhibit 22942-X0545, CPC argument, paragraphs 5-6 and footnote 3.

<sup>507</sup> Exhibit 22942-X0256, PDF page 8.

arising from the application of this subsection and any changes proposed in response to those concerns at the time of the next comprehensive ISO tariff application.

**7.2.3 Terms and conditions: ID 20922 Closure Letter issues: critical information requirements – subsection 3.2(2)**

443. The AESO proposed revisions to subsection 3.2(2) of the current ISO tariff to require market participants to provide, in a SASR, specific information that the AESO will reply upon to plan the connection.

444. The critical information the AESO requires includes:

- the location of the proposed facility;
- the MWs of capacity requested; and
- the requested in-service date of the facilities.

445. The AESO explained that if the critical information changes during the development of the connection project, the connection alternative will generally need to be re-evaluated. Accordingly, the AESO explained that if a market participant requests changes to the critical information for a connection project, then under the proposed subsection 3.7(2) of the 2018 ISO tariff, there may be effects on:

- connection studies;
- the connection alternative (which may no longer be valid); and
- the connection project's progress and position in the AESO's connection process and connection queue.

446. Further, in some cases, changes to critical information may result in a SASR being cancelled by the AESO.<sup>508</sup>

447. CPC argued that the circumstances under which AESO's proposed critical information requirements will trigger reviews or cancellations of SASRs is unclear.<sup>509</sup>

448. CPC noted that in an IR, it asked the AESO to provide information regarding the circumstances under which SASRs would be cancelled, and in response to this request, the AESO stated:

The AESO anticipates that discussions with a market participant about possible amendments to the SASR would take place prior to a SASR being amended. The SASR would be cancelled if the existing connection proposal or alternative could not meet the market participant's updated SASR. Cancellation of the SASR would result in the market participant's project being removed from the connection queue.<sup>510</sup>

449. CPC noted that the AESO is obligated under Section 17(b) of the *Electric Utilities Act* to provide a reasonable opportunity to anyone wishing to exchange electricity in Alberta's electricity market. In addition, CPC submitted that to be approved as just and reasonable, the ISO

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<sup>508</sup> Exhibit 22942-X0163, paragraph 207.

<sup>509</sup> Exhibit 22942-X0545, CPC argument, paragraph 4(b).

<sup>510</sup> Exhibit 22942-X0278, AESO-CPC-2018-NOV01-001, page 3, cited at Exhibit 22942-X0545, CPC argument, paragraph 19.

tariff must set out with clarity how market participants are to be treated. However, CPC submitted that reasonable opportunity to exchange electricity is contingent upon market participants having an awareness of the AESO's requirements for SAS and how the AESO will manage the connection process. Accordingly, CPC is concerned that the AESO's proposed critical information requirements do not provide the clarity necessary for market participants to understand the circumstances in which changes in the "critical information requirements" will lead to review or cancellation of a SASR.<sup>511</sup>

450. CPC submitted that it understands the issues the AESO seeks to remedy in its proposed changes in respect of the advancement of SAS agreements, but considered the AESO's proposed process to be unjust and unreasonable. In particular, CPC submitted that modifications to the AESO's proposal are required to account for the inherent uncertainty that exists when advancing projects through the connection process in a competitive market.<sup>512</sup>

451. In conclusion, CPC submitted that in light of the potentially significant consequences associated with a cancelled SASR and the resulting removal of a market participant's project from the connection queue, the AESO should be directed to establish specific criteria with materiality thresholds, for the review or cancellation of a SASR following a market participant's request for a change in critical information requirements.<sup>513</sup>

452. CPC reiterated its position in reply, arguing that the AESO did not address critical information requirements, and that uncertainty remains with respect to:

- how the AESO will apply the "critical information requirements" to trigger review or cancellation of SASRs;
- what threshold, if any, will be applied to changes in "critical information" beyond which a review will be triggered;
- under what circumstances a change in "critical information" will lead to cancellation of a SASR; and
- whether the AESO will engage in discussions with market participants prior to review or cancellation of SASRs in all cases where critical information changes.<sup>514</sup>

453. Accordingly, CPC submitted that the Commission must deny this proposed change or, in the alternative, direct the relief requested by CPC.<sup>515</sup>

454. The AESO responded that it must have discretion to determine whether a change to critical information is sufficiently material to warrant a review of the connection studies and connection alternatives. Further, as each requested change must be reviewed on a case-by-case basis,<sup>516</sup> establishing specific criteria with materiality thresholds would be overly burdensome and could not contemplate all of the possible scenarios for changes to critical information. The

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<sup>511</sup> Exhibit 22942-X0545, CPC argument, paragraph 19.

<sup>512</sup> Exhibit 22942-X0545, CPC argument, paragraph 20.

<sup>513</sup> Exhibit 22942-X0545, CPC argument, paragraph 21.

<sup>514</sup> Exhibit 22942-X0565, CPC reply argument, paragraph 6.

<sup>515</sup> Note: The Commission considers that CPC's reference to paragraph 61(a) in footnote 6 of its reply argument was in error. Instead, the Commission expects that CPC's intended reference was to paragraph 61(c) of its primary argument.

<sup>516</sup> Exhibit 22942-X0278, AESO-CPC-2018NOV01-001, PDF pages 2-3.

AESO explained that it anticipates that discussions with a market participant about possible amendments to the SASR would take place prior to a SASR being amended. However, the AESO noted that the SASR would be cancelled if the existing connection proposal or alternative could not meet the market participant's updated SASR.<sup>517</sup>

455. Accordingly, the AESO argued that the Commission should reject CPC's recommendation to direct the AESO to establish specific criteria with materiality thresholds, for the review or cancellation of a SASR following a change in critical information. Further, as explained by the AESO, subsection 1.4 of the proposed 2018 ISO tariff obligates the AESO to act reasonably when exercising discretion.<sup>518</sup>

### Commission findings

456. The Commission notes that in its reply argument, CPC suggested that because the AESO did not address critical information requirements in its argument, neither it nor the Commission are any "closer to understanding the AESO's proposed critical information requirements."<sup>519</sup>

457. The AESO's rationale for establishing critical information requirements is set out in its application, and additional clarification was provided by the AESO in its IR responses on this issue. However, CPC did not file evidence on this issue. Therefore, it is understandable that the AESO did not address this matter in argument and instead provided reply argument in response to the arguments raised by CPC.

458. The Commission considers the AESO's proposal to be a reasonable revision because this revision will add certainty to the AESO's transmission system planning process and, contrary to the submissions of CPC, will provide increased clarity to market participants regarding the status of their proposed projects. Stranding of transmission investments has occurred in part due to market participants having failed to carry through on system access requests that the AESO relied on. Moreover, these requests also affect the progress and position of other projects in the connection queue. Consequently, it is reasonable for the AESO to require a level of certainty in order to rely on a SASR for its transmission planning purposes. Further, it is reasonable to expect that changes to critical information in a SASR, if substantive, could require the connection request to be re-evaluated, including a reassessment of the connection alternative, the continued applicability of any connection studies performed and, in some cases, the progress of that project and its position in the connection queue.

459. None of these requirements disturb the AESO's duty under Section 17(b) of the *Electric Utilities Act* to "facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so" as alleged by CPC. The obligation of the AESO is to give all market participants a reasonable opportunity to participate. The actions of a single market participant affect the position of other market participants, and this amendment is intended to ensure that the AESO has the accurate and timely information to assess how it will be able to accommodate system access requests.

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<sup>517</sup> Exhibit 22942-X0278, AESO-CPC-2018NOV01-001, PDF 3, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 9.

<sup>518</sup> Exhibit 22942-X0558, AESO Argument, at paragraphs 100-104, PDF pages 38-40.

<sup>519</sup> Exhibit 22942-X0565, CPC reply argument, paragraph 6.

460. Moreover, the Commission accepts the AESO's evidence that it is necessary for it to have discretion to determine how a change to critical information provided in a SASR may affect the project. The Commission agrees that establishing materiality thresholds would be unhelpful as it would be difficult to provide for all of the possible scenarios to which a threshold must be developed. The Commission finds that the AESO's statutory duty in Section 16(1) of the *Electric Utilities Act*, along with the AESO's obligation in subsection 1.4 of its proposed ISO tariff to act reasonably when exercising its discretion, provide sufficient safeguards without the need to establish cumbersome materiality thresholds.

461. Given the above, CPC's request for a direction to the AESO to establish specific criteria with materiality thresholds, for the review or cancellation of a SASR following a market participant's request for a change in critical information requirements, is denied.

462. As with the Commission's direction in Section 7.2.2, additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.2(2). Accordingly, the Commission directs the AESO to work with market participants for the purposes of addressing any concerns arising from the application of this subsection and any changes proposed in response to those concerns at the time of the next ISO tariff application.

#### **7.2.4 Terms and conditions: ID 20922 Closure Letter issues: timing of GUOC payments**

463. As part of its response to the Commission's Closure Letter, the AESO has proposed that supply market participants be required to pay a GUOC within 30 days of a SAS agreement becoming effective.<sup>520</sup>

464. The proposed changes are found in subsections 7.5(3) and 7.5(4), reproduced below:<sup>521</sup>

**7.5(3)** If the construction of **transmission facilities** is required for a connection project, the owner of a generating facility must pay the owner's contribution for the generating facility in full to the **ISO** within 30 days of the System Access Service Agreement for Rate STS becoming effective pursuant to subsection 3.7(1) of the **ISO tariff**, System Service Access Requests.

**7.5(4)** If the construction of **transmission facilities** is not required for a connection project, the owner of a generating facility must pay the owner's contribution for the generating facility in full to the **ISO** within 30 days after the System Access Service Agreement for Rate STS is executed.

465. The AESO stated that its proposed changes to the GUOC payment provisions are intended to:<sup>522</sup>

- (1) establish greater contractual and financial incentives for market participants to provide accurate and timely information to the AESO;
- (2) increase the AESO's confidence that a connection project will proceed due to financial obligations being triggered upon execution; and

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<sup>520</sup> Exhibit 22942-X0558, AESO written argument, paragraph 34.

<sup>521</sup> Exhibit 22942-X0014.03, Appendix R - Proposed 2018 ISO Tariff, Section 7, PDF page 85.

<sup>522</sup> Exhibit 22942-X0558, AESO written argument, paragraph 35.

- (3) reduce the risk that system transmission facilities are built for connection projects that do not materialize.

466. The AESO submitted that if its proposal is approved, it would not be permitted to issue a refund of GUOC (whether partial or full) prior to a project being energized. The AESO based its opinion on its interpretation of Section 29(4)(a) of the *Transmission Regulation* that the GUOC is refundable “subject to satisfactory operation of the generating unit...” The AESO concluded that a generating unit that is not operable is accordingly not entitled to a refund of the applicable GUOC.<sup>523</sup>

467. CPC, in its argument, stated that changes to the timing of the GUOC payment should be rejected, and expressed concern regarding the AESO’s proposed changes to the process for SASRs. CPC considered that the proposed process changes could result in forfeiture of GUOC payments that are “excessive, unjust, and inconsistent with the statutory scheme governing the AESO.”<sup>524</sup>

468. CPC stressed that under the AESO’s proposal, generating unit owners could potentially forfeit their GUOC payment if its SAS was cancelled, even before a generator achieves operation. Subject to when the GUOC was forfeited, the penalty may exceed any costs incurred by the AESO, TFOs or other stakeholders. CPC added that further analysis is needed to “ensure that forfeiture of GUOC payments prior to commercial operation is proportionate with the costs incurred at each stage of the connection process,”<sup>525 526</sup>

469. CPC stated that Section 29 of the *Transmission Regulation* requires the ISO tariff to include Terms and Conditions providing for the refund of the GUOC over 10 years, subject to the “satisfactory operation of the generating unit” and that the only legislative right for complete forfeiture of the GUOC is under subsection 29(4) of the *Transmission Regulation*, which provides for forfeiture of a GUOC payment “if the generating unit is not operating satisfactorily.”<sup>527</sup> CPC concluded that the AESO’s proposal makes it possible for the GUOC to be forfeited before a generator achieves operation.<sup>528</sup>

470. CPC also argued that the AESO’s proposed changes to the GUOC are in conflict with the AESO’s statutory obligations under the *Electric Utilities Act* to “facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets ... a reasonable opportunity to do so.”<sup>529</sup>

471. Greengate, in its argument, stated that the AESO’s proposal will not achieve its intended objective but instead will encourage market participants to place a project on hold in Stage 2 of the AESO’s connection process in order to mitigate the substantial financial commitment it would be required to provide a short time after a permit and licence is issued, in Stage 5.<sup>530</sup> Greengate argued that the AESO’s proposal will “create an environment of less information for

<sup>523</sup> Exhibit 22942-X0558, AESO written argument, paragraph 38.

<sup>524</sup> Exhibit 22942-X0545, CPC argument, paragraphs 22-23.

<sup>525</sup> Exhibit 22942-X0545, CPC argument, paragraphs 27-28.

<sup>526</sup> Exhibit 22942-X0545, CPC argument, paragraphs 28.

<sup>527</sup> Exhibit 22942-X0545, CPC argument, paragraph 26.

<sup>528</sup> Exhibit 22942-X0545, CPC argument, paragraph 27.

<sup>529</sup> Exhibit 22942-X0545, CPC argument, paragraph 29.

<sup>530</sup> Exhibit 22942-X0551, Greengate final argument, paragraph 11.

project developers, which will lead to increased timelines to develop projects and higher risk premiums.”<sup>531</sup>

472. Greengate explained that generation developers, who do not have the capital to finance a development on their own (unlike government-owned market participants or established generators), need to demonstrate to potential financial backers that a permit and licence has been received in order to receive financing. Greengate suggested that obtaining financing after a permit and licence can take months or years, which is not feasible within the AESO’s proposed 30 days from permit and licence to make its GUOC payment. Greengate noted that renewable energy developers have indicated that the change in the timing of the GUOC payment will increase financial hardship.<sup>532</sup>

473. Greengate explained that fundamental market conditions can change between the time a project begins the interconnection process and ultimately arrives at the point at which the GUOC payment will be required under the AESO’s new proposal. Greengate submitted that imposing that financial risk creates significant barriers to generation project proponents and may result in financial penalties due to conditions outside the control of the project proponent.<sup>533</sup>

474. Greengate argued that without changing its treatment of the GUOC, the AESO has managed to improve its system planning, and suggested that the AESO can find further improvements to its forecasting in relation to transmission planning, without the proposed changes to the GUOC.<sup>534</sup>

475. Greengate argued that the change in timing of the GUOC payment will create barriers to entry and “disproportionately impact the financial positions of a financially larger project proponent versus a small one.” Greengate explained that a project developer is often unable to raise capital, for the project and to finance the GUOC payment, without a confirmed grid connection, which can not be confirmed without a permit and licence.<sup>535</sup>

476. Greengate stated that should the AESO’s requested changes be approved, they would violate the key principles in Section 5(c) of the *Electric Utilities Act*,<sup>536</sup> which states:

... to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant<sup>537</sup>

477. Greengate pointed out that the AESO did not consider the capacity market in its application regarding the payment of GUOC.<sup>538</sup> The Commission notes that the Alberta Government announced that it would not proceed with plans to develop a capacity market,<sup>539</sup> and

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<sup>531</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 12-13.

<sup>532</sup> Exhibit 22942-X0551, Greengate final argument, paragraph 14.

<sup>533</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 19-20.

<sup>534</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 21-24.

<sup>535</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 41-45.

<sup>536</sup> Exhibit 22942-X0551, Greengate final argument, paragraph 46.

<sup>537</sup> *Electric Utilities Act*, page 18.

<sup>538</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 47-55.

<sup>539</sup> <https://www.alberta.ca/release.cfm?xID=642387D0ECA3E-ED8E-6B02-885D35312EBBB3EE>

therefore no further consideration of the impacts of the previously legislated capacity market is required for its decision in this proceeding.

478. Greengate contended that the AESO did not follow its consultation principles for its proposed change to the timing of the GUOC payment, did not conduct a study to evaluate the impact on generation developers, nor did it consider other options to address its concerns.<sup>540</sup>

479. Greengate recommended that the Commission reject the AESO's proposed changes to the GUOC in subsection 7.5(3) of the AESO's terms and conditions and the related subsection 3.7(1) as it relates to the GUOC, as they conflict with the *Electric Utilities Act*. Greengate additionally requested the Commission to direct the AESO to follow its consultation principles when proposing significant tariff changes.<sup>541</sup>

480. The AESO, in its argument, stated its proposed GUOC provisions are intended to mitigate the risk that ratepayers are required to pay for a transmission build where a generator project does not materialize. The AESO added that the proposed terms and conditions are intended to be fair and non-discriminatory, as the same provisions apply equally to all market participants seeking to receive system access service from the AESO.<sup>542</sup>

481. In order to provide context, the AESO provided a theoretical example to demonstrate the magnitude of a GUOC payment for a given project: "For example, a 50 MW wind project, costing in the vicinity of \$100 million, would result in a GUOC payment of \$2.5 million based on the legislated \$50,000/MW maximum contribution rate."<sup>543</sup> (footnotes removed)

482. The AESO described that, delays to in-service dates after a permit and licence has been issued can give effect to a reservation of transmission capacity for such projects. The AESO stated that this is contrary to the Commission's previous determination that there are no transmission rights in Alberta, and can cause challenges in transmission system planning.<sup>544</sup>

483. The AESO asserted that earlier GUOC payments would:

- (a) help to ensure that the AESO has accurate information that a project will proceed as approved;
- (b) reduce the risk that system transmission facilities are built for connection projects that do not materialize;
- (c) benefit supply market participants, as more accurate and reliable transmission system planning information could realize efficiencies that lead to a reduction in the timelines for the AESO's connection process; and
- (d) would provide an earlier signal to other market participants that a market participant is financially committed to an area that may be close to capacity so that the other market participants can consider different locations.

484. CPC, in its reply argument, stated that the AESO's concerns regarding certainty that projects will proceed and the need for information for transmission planning purposes do not

<sup>540</sup> Exhibit 22942-X0551, Greengate final argument, paragraphs 56-62.

<sup>541</sup> Exhibit 22942-X0551, Greengate final argument, paragraph 63.

<sup>542</sup> Exhibit 22942-X0558, AESO written argument, paragraph 40.

<sup>543</sup> Exhibit 22942-X0558, AESO written argument, paragraph 41.

<sup>544</sup> Exhibit 22942-X0558, AESO written argument, paragraph 42.



substantiate complete forfeiture of the GUOC. CPC added that the AESO has not proven that the proposed GUOC forfeiture is consistent with fundamental principles of cost causation.<sup>545</sup>

485. CPC submitted that the AESO's statement that "a refund of GUOC (whether partial or full) prior to energization is neither appropriate nor permissible" is inconsistent with the AESO's amended application and its testimony under cross-examination, where it stated that under certain circumstances some of the GUOC could be refunded.<sup>546</sup>

486. Greengate disputed the AESO's assertion of effective transmission reservations, and stated that the AESO has ignored the actual process it undergoes in its current planning procedures, and that the AESO's remarks in this area should be disregarded.<sup>547</sup>

487. Greengate disagreed with the AESO that the magnitude of the GUOC payment is an insignificant amount to developers, and insisted that the GUOC is significant. Greengate stated that for many of the developers, who end up forfeiting the GUOC payment, it will be one of its more significant development expenses.<sup>548</sup>

488. ENMAX, in its reply argument, agreed in concept with the AESO that ratepayers should not bear the cost of transmission facilities built for generation projects that do not proceed. However, it did not agree with the AESO's proposal that the proponent of a project that does not materialize should not be entitled to receive a refund in the amount paid above the AESO's actual expenditures in respect of the cancelled project.

489. ENMAX also did not agree with the AESO's position that "a refund of GUOC (whether partial or full) prior to energization is neither appropriate nor permissible."<sup>549</sup> ENMAX stated that the intent of the regulatory scheme is to ensure that ratepayers are not responsible for the connection costs of a generating unit that goes on to underperform such that the ratepayer benefit from the interconnection remains below its cost. ENMAX argued that the AESO has discretion, and relied on the following portions of Section 29 of the *Transmission Regulation*:<sup>550</sup>

Section 29(1)(b) states:<sup>551</sup>

The ISO must include in the ISO tariff (a) the amount, determined under subsections (2) and (3), payable by an owner of a generating unit to the ISO, and (b) terms and conditions related to clause (a).

Section 29(3) states:

A charge under subsection (2)(b) may be revised from time to time, but must... (e) be determined and payable in accordance with the ISO rules and the ISO tariff, be paid before commencement of construction of the local interconnection facility and be paid only once for that specific location and generating unit.

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<sup>545</sup> Exhibit 22942-X0565, CPC reply argument, paragraph 12.

<sup>546</sup> Exhibit 22942-X0565, CPC reply argument, paragraph 15.

<sup>547</sup> Exhibit 22942-X0570, Greengate reply argument, paragraphs 5-12.

<sup>548</sup> Exhibit 22942-X0570, Greengate reply argument, paragraphs 16-17.

<sup>549</sup> Exhibit 22942-X0571, ENMAX reply argument, paragraph 7.

<sup>550</sup> Exhibit 22942-X0571, ENMAX reply argument, paragraph 9.

<sup>551</sup> Exhibit 22942-X0571, ENMAX reply argument, paragraph 10.

Finally, Section 29(5) states:

The ISO must make rules to be used to assess the satisfactory performance of a generating unit by generating unit type.

490. The AESO emphasized that it is not proposing that the GUOC be paid upon the execution of an SAS agreement as suggested by CPC. Rather, it has proposed that the GUOC payment be payable within 30 days of an SAS agreement for Rate STS becoming effective, pursuant to subsection 3.7(1) of the proposed 2018 ISO tariff. Prior to execution of an SAS agreement for Rate STS, the AESO planned to require a market participant to provide the AESO with proof that the market participant has sufficient funds available to pay the applicable GUOC when due, pursuant to subsection 3.6(9) of the proposed 2018 ISO tariff.<sup>552</sup>

491. The AESO disagreed with CPC's assertion that the changes to provide the GUOC payment earlier is contrary to the purposes and the statutory scheme governing GUOC payments. The AESO stated that it is "mandated under the EUA and the Transmission Regulation to plan and make arrangements for the expansion or enhancement of the transmission system in a manner that reasonably anticipates the need for such expansion or enhancement based on forecast growth, for the purpose of enabling a fair, efficient and openly competitive market for electricity. [footnote omitted] The AESO is also required to meet its obligations under the EUA and the Transmission Regulation to accommodate all anticipated in-merit energy under normal operating conditions."<sup>553</sup>

492. The AESO stated its proposal for earlier payment of the GUOC was in response to the Commission's Closure Letter from Proceeding 20922, and to "manage the risk that system transmission facilities are over-built or constructed too early."<sup>554</sup> The AESO stated that it has experienced a number of generators that have been granted a permit and licence and have then delayed their in-service dates. The AESO explained that this has the effect of reserving transmission capacity, which creates difficulties for the AESO in its forecasting and transmission system planning.<sup>555</sup>

493. The AESO indicated that it does not expect the changes to the GUOC payment will diminish interest from generation developers in the Alberta market and, therefore, does not contravene the AESO's statutory obligation under the *Electric Utilities Act* to "facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets ... a reasonable opportunity to do so." The AESO added that the earlier payment of the GUOC, coupled with the risk of forfeiture, will provide incentives to generation market participants to provide accurate information to the AESO and better plan their projects, which will:<sup>556</sup>

- (a) prevent market participants from obtaining the unfair opportunity of, in effect, reserving transmission capacity to the disadvantage of other generation market participants; and

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<sup>552</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 21.

<sup>553</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 22.

<sup>554</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 23.

<sup>555</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 23.

<sup>556</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 24.

- (b) lessen the risk of overbuilding the transmission system.

494. The AESO disagreed with Greengate's contention that because the AESO has improved its planning without changing the timing of the GUOC payment, it no longer requires the proposed change to payment timing. The AESO provided an example by which a connection proposal for which a generator received permit and license. The AESO indicated that it would be difficult for it to proceed with another connection in that location if there was no capacity due to the first market participant having obtained its permit and licence. As such, it would be difficult for the AESO to assess whether that first project is going to proceed ahead of the second project.<sup>557</sup>

495. Greengate suggested, as an alternative to modifying the GUOC, the use of appropriate and reasonable application fees be considered instead. Greengate submitted that the AESO had application fee requirements in the past, which were removed in the 2010 tariff application. The AESO restated its response to AESO-Greengate-2018NOV01-001(d), that the application fee was not effective at limiting connection requests to only those for viable projects and, in fact, proved to be a disincentive to withdrawals from the queue, since by doing so, the fee was forfeited. The fee was removed, since the costs incurred by market participants in advancing their projects themselves would provide a better safeguard against unfeasible projects.<sup>558</sup>

496. In response to Greengate's argument that there was inadequate consultation with market participants, the AESO stated that it had brought up its proposal in consultation at stakeholder information sessions on the AESO 2018 tariff application held on June 26, 2017, and May 29, 2018.<sup>559</sup>

### Commission findings

497. The Commission notes that intervenor parties did not submit substantive evidence on the record of this proceeding regarding the proposed timing of the GUOC payments. Argument and reply argument submissions consisted of remarks and observations provided by intervenor parties that the Commission or other parties were not able to explore through the discovery process.

498. Section 29(4) of the *Transmission Regulation* states:

#### Generating unit owner's contribution

...

- (4) The ISO tariff must include terms and conditions providing for the following:
- (a) the refund of money paid under this section, to the owner who paid it, over a period of not more than 10 years from the date the generating unit begins to generate electric energy for the purpose of exchange but not for the purpose of testing or commissioning the unit, subject to satisfactory operation of the generating unit determined under rules made under subsection (5), where satisfactory operation may vary by generation type;
  - (b) forfeiture to the ISO of money paid under this section, or suspension of the refunds, if the generating unit is not operated satisfactorily;
  - (c) the means and times at which the refunds are to be made;

<sup>557</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 26.

<sup>558</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 28.

<sup>559</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 30.

- (d) the prudent administration, management and investment of money held by the ISO under this section and for the accounting for those funds;
- (e) the disbursement of money earned on investments.

499. Section 29(4) refers to the terms for refund and forfeiture of the GUOC payment. The AESO submitted that if its proposal is approved, it would not be permitted to issue a refund of a GUOC payment (whether partial or full) prior to a project being energized, and that a generating unit that is not operable would not be operating satisfactorily and, accordingly, would not be entitled to a refund of the applicable GUOC payment.

500. As discussed above, CPC argued that the AESO had provided instances where a GUOC payment could be refunded under its proposal.<sup>560</sup>

501. The Commission does not agree with CPC that the AESO's statement is inconsistent with the AESO's amended application, Section 29(4) and its testimony under cross-examination, where it stated that under certain circumstances, a portion of the GUOC payment could be refunded under its proposal.

502. The Commission agrees that changing conditions between a SAS agreement becoming effective and energization may result in a partial forfeit of a GUOC payment. However, the AESO is only able to refund an eligible non-forfeited portion after a project is energized. As stated by Ms. Kerr, on behalf of the AESO:

Q. So just so I'm clear, in the SAS agreement, the bid documents, but nothing further on record in this proceeding that speaks to criteria or methodology with respect to calculating that portion of GUOC that might come back to generating unit owners between SAS agreement being signed and energization?

A. MS. KERR: Apologies. Like I was saying, we have -- the calculations that we use to calculate what the actual GUOC payment is going to be is a simple one. It's megawatts times location times ten years. So when megawatts change, as an example, if you go from 50 to 40, and you've done this after the execution of your SAS agreement, you would forfeit the dollars associated with those 10 megawatts of your GUOC. But you would still be eligible for the refund as long as you reached your ISD date of the 40 megawatts of GUOC that you had paid.

Q. Thank you. Can you help me understand what happens if there's a full cancellation of the SAS?

A. MS. KERR: After it's been executed?

Q. Yes.

A. MS. KERR: You would forfeit the GUOC.

Q. And there would be no methodology or no calculation or no criteria for a partial amount of those dollars to come back to the generating unit owner.

A. MS. KERR: There would not be if you cancelled.<sup>561</sup>

503. The Commission finds that the AESO's proposed terms and conditions regarding supply market participants being required to pay a GUOC within 30 days of an SAS agreement

<sup>560</sup> Transcript, Volume 1, page 150, line 25 to page 155, line 10.

<sup>561</sup> Transcript, Volume 1, pages 153-154.

becoming effective does not violate Section 29 of the *Transmission Regulation* and will help to ensure that the AESO has more accurate information for transmission planning purposes.

504. The Commission also finds the AESO's proposal to accelerate the payment of GUOC to be a reasonable response to the Closure Letter that required the AESO to effectively manage the risk that system transmission facilities are overbuilt or constructed too early, as well as address the issue of generators holding permit and licences with delayed in-service dates, effectively reserving transmission capacity.

505. The Commission finds that the AESO's proposed changes regarding the timing of the GUOC payment are reasonable, and assist the AESO in achieving its mandate to enable a fair, efficient and openly competitive market for electricity. Therefore, the Commission approves the AESO's proposal as filed.

### **7.2.5 Terms and conditions: ID 20922 Closure Letter issues: system-related vs. participant-related classification of transmission project costs**

506. The AESO proposed several changes to its terms and conditions in how it determines the classification of a connection project as a system-related or participant-related cost.

#### **7.2.5.1 Mandate to pursue these changes**

507. EDTI argued that the AESO proposed a number of substantive changes to its customer contributions and took note of the following key changes to system vs. customer classification included in the 2018 ISO tariff:

- The inclusion of a new defined term "radial circuit" and related changes, which has the effect of significantly expanding the types of facilities within projects classified as participant-related.
- The effective removal of the concept of "looped facilities" from the tariff, thereby decreasing the predictability of whether proposed transmission projects would be classified as system-related rather than participant-related.
- The deeming of new facilities requested by a market participant as participant-related, irrespective of factors that would otherwise cause the facilities to be classified as system-related.
- A significant increase in the AESO's general discretion to deem costs as participant-related.

508. EDTI contended that the AESO's decision to pursue the above noted changes was contrary to findings in several prior ISO tariff decisions, including the following:

- Decision 2005-096: EDTI noted that the Commission's predecessor rejected an AESO proposal in that proceeding to cease emphasizing the concept of "radial" and "looped" facilities in allocating participant- and system-related costs, and instead to deem most costs to be system, except for a list of specific items that would be covered by the market participant. EDTI noted the Commission's predecessor opted for the approach reflected in the AESO's current terms and conditions.<sup>562</sup>

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<sup>562</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 75-80.

- Decision 2009-126: EDTI noted that in its decision in respect of the Southern Alberta Transmission Reinforcement (SATR) Project, the Commission discussed the mandate of the AESO to plan a flexible and forward looking transmission system that reasonably anticipates new generation. EDTI submitted that the AESO did not provide any rationale in the application for significant changes from this approach.<sup>563</sup>
- Decision 2010-606: EDTI noted that the Commission rejected a list of specific cost items that the AESO proposed to be designated as system-related. EDTI submitted that, in so doing, the Commission determined that the currently approved terms and conditions provided a reasonable balance between participant-related and system-related costs.<sup>564</sup>
- Decision 2012-362: Although the AESO cites this decision in support of its proposed changes, EDTI argued that Decision 2012-362 was primarily concerned with the determination of appropriate maximum investment levels and with how to best allocate contributions between regulated utilities. As such, EDTI Decision 2012-362 has no bearing on the changes that the AESO has proposed in the application.<sup>565</sup>
- Decision 2014-242: EDTI noted that the AESO references the Commission’s findings at paragraph 469 as providing guidance for “[b]uilding system transmission facilities only if there is enough certainty that the project is required.” However, EDTI stated that the relevant sections of Decision 2012-242 pertained to an AESO proposal to remove advancement cost provisions, and automatically to deem an expansion of a system facility to be a system-related cost. EDTI noted that although the Commission rejected these proposals, the Commission’s findings in that decision did not direct or even indicate a desire for the fundamental changes it set out in the application with respect to:
  - the classification of costs between participant-related and system-related
  - the expanded definition of “radial” facilities, or
  - the removal of looped facilities from the list of system-related costs.<sup>566</sup>
- Decision 3473-D02-2015: EDTI noted that the Commission rejected a series of proposals made by the AESO in its refiling application pursuant to Decision 2014-242. Again, although the Commission indicated its intention to convene a separate proceeding to address the system-related vs participant-related classification matters, the Commission eventually decided that these issues should be dealt with as part of the 2018 ISO tariff. However, Decision 3473-D02-2015 represents the “last word” by the Commission and the AESO did not have the mandate in the present proceeding to conduct the wholesale amendments it proposed.<sup>567</sup>

509. In consideration of the above, EDTI submitted that the terms and conditions changes proposed by the AESO in the current application, are not supported by findings that the AESO has referenced in support, and are often inconsistent with findings and decision that the

<sup>563</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 81-82.

<sup>564</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 83-85.

<sup>565</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 86-89.

<sup>566</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 90-93.

<sup>567</sup> Exhibit 22942-X0550, EDTI argument, paragraphs 94-100.

Commission has made. In view of this, EDTI submitted that the changes proposed in the application should be denied.<sup>568</sup>

510. In its argument, ENMAX submitted that because of the broad implications of the AESO's proposed new definition of a "radial circuit" and because the new clause in subsection 4.2(2)(c) along with other substantial classification changes proposed in Section 4 of the terms and conditions have broad implications, further consultation with market participants is required.

511. ENMAX's principal concern was with the AESO's broad discretion to classify costs between system-related and participant-related. In light of its concerns, ENMAX submitted that the Commission should direct the AESO to undertake additional consultation with stakeholders before it approves any of the cost classification changes proposed by the AESO.

512. In reply, the AESO took issue with EDTI's suggestion that it had not provided discussion of its rationale for specific changes to the provisions of its terms and conditions dealing with the classification of costs as between system-related and participant-related. However, to address such concerns, the AESO provided additional rationale in its reply argument with respect to the following issues identified by EDTI:

- It disagreed with EDTI's suggestion arising from removal of subsection 8.2 of the current tariff that there is insufficient guidance as to what costs will be deemed to be transmission costs, arguing that its proposed subsection 4.2 provides a more detailed description of the transmission facility costs it would classify as either participant-related or system-related.<sup>569</sup>
- It contended that the removal of words "contiguous" and "non-contiguous" from the current subsection 8.3(2) of the terms and conditions would improperly imply that it is only the costs of facilities that are adjacent to or adjoin a connection project that can be participant-related costs.<sup>570</sup>
- It rejected EDTI's allegation that AESO's proposed definition of "radial circuit" is complex and unclear, arguing that the proposed definition provides clarity that a second circuit that exists for the sole benefit of a single market participant that extends from the same system element as the first circuit and that is operated normally open does not fundamentally change the nature of a transmission facility from radial to looped.<sup>571</sup>
- It considered its proposed subsection 4.2(2)(c) to be appropriate to provide market participants with clarity regarding additional (i.e., second, third, fourth, etc.) transmission lines that, as EPCOR describes it, will be classified by the AESO as participant-related contrary to EDTI's assertions that it is ambiguous.<sup>572</sup>
- It contended that EDTI's concern with the AESO's proposed subsection 4.2(2)(l) requiring the cost of transmission facilities to be assessed on a "replacement cost new" basis ignored the fact that the "replacement cost new" requirement under subsection 4.2(2)(l) is intended to ensure that the estimated costs of existing system

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<sup>568</sup> Exhibit 22942-X0550, EDTI argument, paragraph 101.

<sup>569</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(a).

<sup>570</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(b).

<sup>571</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(c).

<sup>572</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(d).

transmission facilities, being reclassified as participant-related, can be compared by the AESO on an equivalent (apples-to-apples) basis.<sup>573</sup>

- It responded that EDTI's argument, that the AESO's proposed advancement cost framework relies too much on the AESO's discretion exercised on a case-by-case basis and, therefore, will make it more difficult for a market participant to identify its participant-rated costs prior to filing a SASR, was fundamentally flawed because there is no way for a market participant to identify the extent of its participant-related costs prior to filing a request for system access service.<sup>574</sup>
- It rejected EDTI's view that the AESO should "better specify" the types of costs that will be subject to advancement treatment as unnecessary as its current and proposed approach to advancement cost classification is understood by market participants.<sup>575</sup>
- It claimed that EDTI's concern that proposed subsection 4.2(3)(a)(i)-(iii) allows the AESO to charge advancement costs on a system expansion project that the AESO had never previously conceived, ignores the fact that, in response to a system access service request, the AESO would select its preferred alternative based on lowest overall long-term cost.<sup>576</sup>
- It agreed in principle to EDTI's proposition that advancement costs should be based on when the AESO would require the facilities, in the absence of the market participant's request. However, as detailed in the amended application, the AESO considered it reasonable to limit advancement costs payable under subsection 4.2(3)(a)(i)-(ii) to a maximum five-year time frame, which aligns with the typical five-year planning window that the AESO requires to plan the transmission system in the near term, rather than to potentially charge load market participants with up to 20 years of advancement.<sup>577</sup>
- It considered that, contrary to EDTI's suggestion that a further definition of "avoidable construction costs" is required, that the definition was clear on its face.<sup>578</sup>

513. In response to ENMAX's request for additional consultation prior to implementation of its proposed changes, the AESO submitted that it did have stakeholder consultations on this issue<sup>579</sup> and that further consultation is unnecessary.

### Commission findings

514. The Commission finds that the changes to the classification of costs set out in the AESO's proposed tariff follow directly from the concerns identified by the Commission in its Closure Letter. EDTI's failure to address the Closure Letter in its submissions significantly diminishes the persuasiveness of its argument that the AESO does not have a mandate to pursue the changes it has proposed. The Closure Letter articulated the Commission's concerns with how the AESO has historically characterized its obligations in respect of the initiation and completion of system transmission projects, as well as the price signals given to market participants that

<sup>573</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(e).

<sup>574</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(f).

<sup>575</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(g).

<sup>576</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(h).

<sup>577</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(i).

<sup>578</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(j).

<sup>579</sup> Exhibit 22942-X0024.02, Amended Appendix C, PDF pages 18, 38, 46, 448, 450, 467, 515, 521, 581.



have contributed to the extent and speed at which system transmission projects have been constructed.

515. Further, the Commission accepts the AESO's evidence that it engaged in stakeholder consultations regarding these issues.

516. Even had the AESO pursued tariff changes in this proceeding that it considered to be necessary absent prior identification of these issues by the Commission, there is no statutory provision that prevents the AESO from doing so. To the contrary, the AESO must prepare a tariff that meets the requirements of Section 30 of the *Electric Utilities Act* and must carry out its duties in compliance with sections 16 and 17 of the Act. If the AESO considers that it must amend provisions in order to meet those requirements, it has a responsibility to bring forward those amendments.

517. In consideration of the foregoing, the Commission rejects the positions of EDTI and ENMAX that the AESO did not have a mandate to bring forward these concerns.

518. The Commission's findings in response to the specific concerns that EDTI has raised related to the classification of costs as between system-related and participant-related follow.

#### 7.2.5.2 AESO discretion in application of contribution policy

519. EDTI noted that the AESO had initially proposed to consolidate various provisions describing how it should exercise its discretion into one section of the terms and conditions as follows:

1.4 The **ISO** and a **market participant** who has requested or is receiving **system access service** must act reasonably in exercising any discretion available to them under the **ISO tariff**.

520. However, approximately a week before the start of the oral hearing, the AESO filed a letter<sup>580</sup> that described an amendment to its applied-for terms and conditions to include a new subsection 4.10:

The AESO has determined that a discretionary provision in the current ISO tariff, which was deleted from the proposed 2018 ISO Tariff, should be restored.

Specifically, subsection 10 of Section 8, Construction Contributions for Connection Projects of the current ISO tariff will be restored to become new subsection 4.10(3) in Section 4, Classification and Allocation of Connection Project Costs, of the proposed 2018 ISO tariff, as follows:

4.10 The ISO may exercise discretion in the application of the construction contribution provisions in the ISO tariff.

521. EDTI noted that the AESO's proposed subsection 4.10 effectively replaces the currently approved subsection 8.10, as follows:

The ISO may exercise discretion in the application of the construction contribution provisions in the ISO tariff, including the determination of costs to be system-related in

<sup>580</sup> Exhibit 22942-X0453, cited at Exhibit 22942-X0550, EDTI argument, paragraph 68.

certain circumstances that might, under strict application of the construction contribution provisions, have been classified as participant-related.

522. EDTI expressed concern that the AESO's proposed subsection 4.10 is substantially revised from the current tariff's subsection 8.10 without explanation. In particular, EDTI was concerned with the removal of the phrase "including the determination of costs to be system-related in certain circumstances that might, under strict application of the customer contribution provisions, have been classified as participant-related" in the revised provision.<sup>581</sup>

523. EDTI submitted that the revised wording in the new subsection 4.10 was troubling because it appears to narrow the scope of the AESO's discretion to "do the right thing."<sup>582</sup>

### **Commission findings**

524. By expressly providing the AESO with broad discretion in the classification of costs as between system-related and participant-related, subsection 8.10 provides a means by which the AESO can adapt unique circumstances that may not be contemplated at the time of comprehensive ISO tariff applications. In this regard, the Commission notes that subsection 8.10 was central to the approach taken by the AESO in the proceeding leading to Decision 22125-D01-2018 which considered the replacement of isolated generation with a radial transmission line serving the Jasper area.<sup>583</sup>

525. The Commission agrees with EDTI that by excluding the phrase, "including the determination of costs to be system-related in certain circumstances that might, under strict application of the customer contribution provisions, have been classified as participant-related," the AESO's proposed subsection 4.10 may not provide adequate discretion to the AESO to vary the application of certain aspects of its tariff contribution policy when circumstances warrant. Accordingly, the Commission directs the AESO to revise its proposed subsection 4.10 at the time of its refiling application to substantially replicate the wording in the current tariff's subsection 8.10.

#### **7.2.5.3 Scope of connection project costs**

##### **Consideration of project scope in relation to ISO preferred alternative**

526. EDTI noted that the AESO's proposed subsection 4.2(1) replaces provisions describing the scope of the costs considered to be part of a connection project that are set out in subsection 8.2 of the approved ISO tariff. EDTI noted that the AESO's proposed subsection 4.2(1) determines the scope of connection project costs in relation to certain provisions set out in subsection 3.4 of its proposed tariff, which addresses system access requests.<sup>584</sup>

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<sup>581</sup> Exhibit 22942-X0550, EDTI argument, paragraph 70.

<sup>582</sup> Exhibit 22942-X0550, EDTI argument, paragraph 70.

<sup>583</sup> Decision 22125-D01-2018: Alberta Electric System Operator, Needs Identification Document, Proceeding 22125, Application 22125-A001; AltaLink Management Ltd., Facility Applications, Proceeding 22125, Applications 22125-A002 and 22125-A003; ATCO Electric Ltd., Facility Applications, Proceeding 22125, Applications 22125-A004 to 22125-A006, May 4, 2018, paragraph 320.

<sup>584</sup> Exhibit 22942-X0550, EDTI argument, paragraph 19.

527. EDTI set out the relevant provisions in a table, reproduced below:

AESO proposed	Currently approved
<p>4.2(1) All costs of a connection project as determined by the ISO under subsection 3.4 of the ISO tariff, System Access Service Requests, must be classified as either participant-related or system-related.</p> <p>...</p> <p>3.4(1) If construction of <b>transmission facilities</b> is required for a connection project, the <b>ISO</b> must determine how to respond to the <b>system access service</b> request, and select the ISO's preferred connection alternative taking into account relevant factors including the following:</p> <p>(a) the overall long-term cost of a connection alternative, including, as applicable:</p> <p>(i) if the <b>system access service</b> request was submitted by the <b>legal owner</b> of an <b>electric distribution system</b>, all distribution costs;</p> <p>(ii) costs classified as participant-related in accordance with subsection 4.2(2) of the <b>ISO tariff</b>, Classification and Allocation of Connection Projects Costs;</p> <p>(iii) costs associated with <b>system transmission facilities</b>, being <b>transmission facilities</b> that the ISO identified in subsection 3.4(1)(b) and (c) below; and</p> <p>(iv) all other transmission costs (including the costs of any non-wires solutions) not included in subsection 3.4(1)(a)(i), (ii) and (iii) above required for the connection;</p> <p>...</p> <p>3.4(6) The <b>ISO</b> must calculate a <b>construction contribution</b> for a connection project and must classify all transmission costs of the connection project as either participant-related or system-related in accordance with section 4 of the <b>ISO tariff</b>, Classification and Allocation of Connection Project Costs.</p>	<p>8.2 The <b>ISO</b> must determine the costs of a connection project for a <b>market participant</b> to be those costs reasonably associated with facilities that:</p> <p>(a) a <b>legal owner</b> of a <b>transmission facility</b> owns and operates;</p> <p>(b) are required in order to:</p> <p>(i) provide <b>system access service</b> to a new <b>point of delivery</b> or <b>point of supply</b>; or</p> <p>(ii) increase the capacity of or improve <b>system access service</b> to an existing <b>point of delivery</b> or <b>point of supply</b>; and</p> <p>(c) are reasonably required to meet the <b>market participant's</b>:</p> <p>(i) <b>demand</b> and supply forecast; and</p> <p>(ii) <b>reliability</b> and operating requirements.</p> <p>8.3(1) All costs of a connection project will be classified as either participant-related or system-related.</p>

Source: Exhibit 22942-X0550, EDTI final argument, paragraph 19.

528. EDTI noted that the costs of a proposed connection project include costs determined in relation to the “ISO’s preferred connection alternative, as set out in the AESO’s proposed Subsection 3.4(1) of its terms and conditions.”<sup>585</sup> The AESO explained that the costs it intends to consider in relation to subsection 3.4(1) include “all material costs arising from the connection project,” while taking into account “all relevant current and projected efficiency, timing, land use, safety, environmental, and other applicable considerations.”<sup>586</sup>

529. Having regard to these provisions, EDTI submitted that the AESO’s proposed subsection 4.2(1) contains a much broader scope of costs than provided for in subsection 8.2 of

<sup>585</sup> Exhibit 22942-X0550, EDTI argument, paragraph 19

<sup>586</sup> Exhibit 22942-X0550, EDTI argument, paragraph 2, footnote 19 Exhibit 22942-X0163, Amended application, paragraph 222.

the AESO’s currently approved tariff. Further, EDTI expressed concern that the proposed subsection 3.4(6) requires the AESO to classify “all costs of the connection project” as either participant-related or system-related, but provides no guidance as to what costs the AESO will deem to be transmission costs.<sup>587</sup>

530. In reply, the AESO explained that subsection 4.2 of its proposed 2018 ISO tariff includes a more detailed description of the transmission facility costs that the AESO would deem to be either participant-related or system-related. In addition, the AESO noted that the details of any “transmission costs” are addressed through cost estimating requirements that are set out in Section 504.5 of the ISO rules, and in Section 6 of Rule 007.<sup>588</sup>

### “Lead in” to participant-related costs definition

531. EDTI expressed concern in subsection 2.2.1 of its argument, with the “lead-in” phrases used in the current approved and the AESO’s proposed ISO tariff to describe the scope of participant-related costs. EDTI provided a comparison of the relevant phrases used in the proposed and current tariffs, as follows:

AESO proposed	Currently approved
4.2(2) Participant-related costs are the costs deemed necessary by the <b>ISO</b> to accommodate a connection project, when taking into account the <b>ISO’s transmission system</b> planning obligations, and include costs associated with:	8.3(2) Participant-related costs will be those costs related to a contiguous connection project including costs associated with:

532. EDTI observed that the currently approved subsection 8.3(2) wording states that participant costs are “those costs related to a contiguous connection project,” whereas the proposed wording in subsection 4.2(2) of the 2018 ISO tariff is not objective. Unlike the wording currently in effect, the revised provision gives the AESO excessively broad discretion to “deem” costs to be participant-related rather than system-related.

533. EDTI submitted that the AESO acknowledged in the application that the intended purpose of moving to the lead-in language of subsection 4.2(2) was to allow the AESO to deem a greater range of facility costs to be participant-related.

534. EDTI argued that such broad and unrestricted discretion is the antithesis to objectives like clarity, objectivity, certainty, and predictability, and expressed concern that the AESO’s application neither explained why such broad discretion was required, nor offered any boundaries to circumscribe its discretion.<sup>589</sup> Consequently, EDTI requested that the changes should be denied.<sup>590</sup>

535. The AESO rejected EDTI’s contention that it had failed to provide sufficient justification for the removal of these terms in the application. It replied that the continued inclusion of the

<sup>587</sup> Exhibit 22942-X0550, EDTI argument, paragraph 22.

<sup>588</sup> Exhibit 22942-X0558, Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*, Section 6, NID8, NID16 and NID24, cited at paragraph 161 (a).

<sup>589</sup> Exhibit 22942-X0550, EDTI argument, paragraph 32.

<sup>590</sup> Exhibit 22942-X0550, EDTI argument, paragraph 36.

word “contiguous” would improperly imply that participant-related costs are limited to the costs of facilities that are either adjacent to or adjoining a connection project.<sup>591</sup>

### Commission findings

536. In Section 7.2.2 (Closure letter – ISO preferred alternative), the Commission found that the AESO should have discretion with respect to Subsection 3.4(1) and that the AESO will exercise its discretion reasonably as it is required to do pursuant to Section 16 of the *Electric Utilities Act* to act responsibly.

537. With respect to EDTI’s concern with the “lead in” clauses applied to the determination of participant-related costs, the Commission considers that the change from defining participant-related costs in relation to what constitutes a “contiguous connection project” as used in the existing tariff’s subsection 8.3(2) to the proposed tariff’s proposed language in subsection 4.2(2), which grants the AESO the ability to deem costs to be participant-related if the AESO considers the costs to be “necessary to accommodate a connection project,”<sup>592</sup> to be reasonable and consistent with the AESO’s overall approach to the issues raised in the Closure Letter. The Commission accepts the AESO’s submission that the continued inclusion of the term “contiguous” can be confusing because, as noted by the AESO in its application:

The word “contiguous” infers that only the cost of facilities that form part of a connection project or that are facilities adjacent to or adjoining the connection project would be participant-related costs. However, the AESO notes that current subsections 3(2) (f) and (j) refer to telecommunications and remedial action schemes, which are connection project components that may be upstream or downstream of the radial connection. Further, there may be instances where other non-contiguous facilities are required only for the sole benefit of a connecting market participant. The wording of the current subsection has caused confusion as some market participants have considered that the cost of such non-contiguous facilities should be classified as system-related costs.<sup>593</sup>

538. The AESO’s proposed removal of the terms “contiguous” and “non-contiguous” from the current subsection 3(2) of Section 8 of the ISO tariff is approved.

### 7.2.5.4 Changes to looped vs. radial classification framework

#### New exceptions to looped vs. radial framework

539. EDTI opposed the AESO’s proposal to amend or remove several provisions in the current ISO tariff’s terms and conditions that set out the framework for the classification of transmission project costs between system-related and participant-related. Of particular concern was the AESO’s proposals with respect to radial and looped facilities. EDTI submitted that these proposed changes are significant and would substantially change the currently approved cost classification scheme.<sup>594</sup>

540. EDTI submitted that since the release of Decision 2001-6, the ISO tariff has classified costs as between participant-related and system-related on the basis of a framework that reflects

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<sup>591</sup> Exhibit 22942-X0163, Amended application, paragraph 254, PDF page 65, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 161(b).

<sup>592</sup> Exhibit 22942-X0014.03, subsection 4.2(2), PDF page 62.

<sup>593</sup> Exhibit 22942-X0002.01, paragraph 243.

<sup>594</sup> Exhibit 22942-X0550, EDTI argument, paragraph 26.

a dichotomy between “looped” facilities and “radial” lines. This framework was summarized by the Commission in Decision 3473-D02-2015, as follows:

53. Another commonly used classification is the classification of transmission facility project costs as either “non-radial” or “radial,” or alternately “looped” or “nonlooped.” These classification concepts were first introduced into the transmission tariff of the AESO’s predecessor and adopted by the Commission’s predecessor, the Alberta Energy and Utilities Board (board) with the issuance of Decision 2001-6. In that decision, the board adopted the convention that new transmission lines that connect to the existing transmission system at one point, defined as “radial” lines, would generally be classified as customer or “participant-related” and new transmission lines that connect to the existing transmission system at two points, defined as “looped” or “non-radial” lines would be classified as “system-related.” Applying these terms, “looped” and “radial,” as the primary basis for classification of new transmission lines, costs were defined as “system-related” for “looped configurations” and “participant-related” for “radial lines.” If the radial line initially intended to serve one market participant was subsequently used by an additional market participant, the first market participant would be eligible for a refund of a portion of the “participant-related” costs it paid.<sup>595</sup>

541. EDTI set out the changes in relevant definitions below:

AESO proposed	Currently approved
<p>4.2(2) Participant-related costs are the costs deemed necessary by the <b>ISO</b> to accommodate a connection project, when taking into account the <b>ISO’s transmission system</b> planning obligations, and include costs associated with:</p> <p>...</p> <p>(b) a <b>radial circuit</b>, including double-radial configurations, with only 1 transmission source from the <b>transmission system</b> to the connection substation;</p> <p>(c) a new additional transmission line for a <b>point of delivery</b> or <b>point of supply</b> that is served from an additional transmission source and that is either required only to serve the <b>point of delivery</b> or <b>point of supply</b> or is requested by a <b>market participant</b>;</p> <p>...</p> <p>4.2(4) System-related costs are the costs of the connection project that have not been classified as participant-related in accordance with subsection 4.2(2) and (3) above, and include incremental <b>transmission facilities</b> in excess of the <b>ISO’s</b> preferred connection alternative in accordance with subsection 3.4 of the <b>ISO tariff, System Access Service Requests</b>, to serve the <b>market participant</b> where, as determined by the <b>ISO</b>, economics or <b>transmission system</b> planning support the development of such <b>transmission facilities</b>.</p>	<p>8.3(2) Participant-related costs will be those costs related to a contiguous connection project including costs associated with:</p> <p>...</p> <p>(b) new radial transmission lines, including double- radial configurations, with only one (1) transmission source from the <b>transmission system</b> to the connection substation;</p> <p>...</p> <p>8.3(3) System-related costs will be those costs related to a connection project including non contiguous components of the project and any costs associated with:</p> <p>(a) looped <b>transmission facilities</b>, which are facilities that increase the number of electrical paths between any two (2) substations, excluding the substation serving the <b>market participant</b> and which exclude any new radial transmission line;</p> <p>...</p> <p>(c) <b>transmission facilities</b> in excess of the minimum size required to serve the <b>market participant</b> where, in the opinion of the <b>ISO</b>, economics or system planning support the development of such facilities.</p>

<sup>595</sup> Decision 3473-D02-2015, paragraph 53, cited at Exhibit 22942-X0550, EDTI argument, paragraph 37.

542. EDTI argued that the AESO was proposing radical changes to its terms and conditions and should not be permitted to do so without fully explaining and justifying its proposed changes.<sup>596</sup>

543. In particular, EDTI noted that the updated terms and conditions have removed the concept of looped facilities from the AESO's contribution policy framework, including within the AESO's proposed subsection 4.2(4).<sup>597</sup> EDTI claimed that the language proposed in subsections 4.2(2)(b) and (c) and 4.2(4) to replace the existing tariff's subsections 8.3(2)(b) and 8.3(3)(a) and (c), including the newly defined term "radial circuit," is complex and unclear. EDTI contended that the new provisions create greater ambiguity, uncertainty and lack of predictability for market participants as compared to the currently approved provisions.<sup>598</sup>

544. EDTI also argued that the AESO's proposed subsection 4.2(2)(c) adds an entirely new description of a situation that the AESO will classify as participant-related.<sup>599</sup> EDTI submitted that subsection 4.2(2)(c), as currently drafted, can only reasonably be interpreted as meaning that, if a new additional transmission line from an additional transmission source is requested by the market participant, it will be classified as participant-related irrespective of any other consideration.<sup>600</sup>

545. The AESO rejected EDTI's characterization that its proposed changes represent radical changes to the looped vs. radial distinction discussed in prior Commission and Alberta Energy and Utilities Board decisions. It replied that the looped versus radial scheme remains in place as a valid rule of thumb for projects that arise from SASRs. Accordingly, it would be unreasonable to strictly rely on the radial vs. looped criteria without exercising discretion about the circumstances of specific projects.<sup>601</sup>

546. The AESO responded that its proposed language in subsection 4.2(2)(c) provides clarity to market participants. In its view, if a market participant requests an additional line, the cost of the additional line should be borne by the market participant. The AESO also indicated that it had proposed subsection 4.2(2)(c) to reflect the underlying fact that the new lines in the circumstance described in subsection 4.2(2)(c) would exist solely for the exclusive benefit of the market participant at the applicable point of supply or point of delivery.<sup>602</sup> Further, the AESO indicated that it required the specific language in subsection 4.2(2)(c) because the AESO's proposed definition of a "radial circuit" did not, by itself, capture this intent (because this type of request does not extend from the same "system element" as the radial circuit definition does).

### **New definition of "radial circuit"**

547. EDTI submitted that its concern arises from the fact that, in its proposed subsection 4.2(2)(b), the AESO introduces a concept called a "radial circuit," which it considered

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<sup>596</sup> Exhibit 22942-X0550, EDTI argument, paragraph 158.

<sup>597</sup> Exhibit 22942-X0550, EDTI argument, paragraph 38.

<sup>598</sup> Exhibit 22942-X0550, EDTI argument, paragraph 41, first bullet.

<sup>599</sup> Proposed subsection 4.2(2)(c).

<sup>600</sup> Exhibit 22942-X0550, EDTI argument, paragraph 43.

<sup>601</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 158.

<sup>602</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(d).

allocated much greater costs as participant-related costs than the approach taken in the current ISO tariff's terms and conditions that relies primarily on the term "radial transmission lines."<sup>603</sup>

548. EDTI noted that the AESO has included the new term "radial circuit" in Appendix U to the application, as follows:

"radial circuit" means an arrangement of contiguous system elements extending from a single system element on the networked transmission system in a linear or branching configuration to the facilities of one or more market participants, which is the only circuit for power to flow between the networked transmission system and the facilities of one or more market participants under normal operating conditions, including when the circuit is connected to another circuit through a switching device that is operated normally open.<sup>604</sup>

549. EDTI submitted that the AESO's new "radial circuit" definition and participant-related classification exception is a fundamental change in approach because it changes classification from system-related to participant-related. It argued that the AESO's explanation that the change was required to prevent DFOs from trying to have transmission facilities they request through SASRs be deemed system-related did not justify a change of this magnitude. It contended that because the definitions of "transmission facility" and "electric distribution system" are mutually exclusive based on voltage levels, there was no basis to change from the "looped" vs "radial" framework to one based on who initiated the project.

550. The AESO rejected EDTI's argument that the AESO's proposed definition of a "radial circuit" is complex and unclear. It submitted that, when read carefully, its proposed definition would provide clarity and precision to the radial concept. As explained in the oral hearing, the AESO argued that it added the "normally open breaker" language to provide clarity to the AESO's views that this configuration should be classified as participant-related. In particular, this change reflected the AESO's views that:

- A second circuit that exists for the sole benefit of a single market participant that extends from the same system element and that is operated "normally open" does not fundamentally change the transmission facility from radial to looped.
- The fundamental driver of system-related classification rather than participant-related is that the facilities benefit multiple market participants rather than a single market participant.

### Commission findings

551. The Commission agrees with EDTI's submission that the changes that the AESO has proposed in subsection 4.2(2) and 4.2(4) represent substantive changes. However, the Commission considers these changes to be reasonable in the context of the issues identified in the Closure Letter, and the AESO's overall response to those issues.

552. The Commission also notes EDTI did not address in its argument submissions how maintaining the current tariff provisions addresses the issues raised by the Commission in the

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<sup>603</sup> Exhibit 22942-X0550, EDTI argument, paragraph 38.

<sup>604</sup> Exhibit 22942-X0163, Amended application, Appendix U – Defined Terms Used in the ISO Tariff; Exhibit 22942-X0017.01, cited at Exhibit 22942-X0550, EDTI argument, paragraph 39.



Closure Letter. Consequently, EDTI's avoidance of these issues raised in the Closure Letter significantly diminishes the persuasiveness of its argument.

553. It is within the scope of the AESO's mandate to propose changes to the looped vs. radial classification framework adopted in Decision 2001-6. Although the AESO has indicated that it will remain guided by the looped vs. radial framework in making decisions about which projects should be afforded system-related treatment under the AESO's contribution policy, the AESO is not bound by this framework as long as its proposed treatment is consistent with its duty to act responsibly under Section 16 of the *Electric Utilities Act*.

554. The Commission finds that the addition of the term "radial circuit" adds clarity. The Commission accepts AESO's submission that the proposed subsection 4.2 provides a more detailed description of the transmission facility costs that the AESO would classify as either participant-related or system-related for a connection project.

555. The Commission shares the view of the AESO that facilities with a normally open breaker are effectively radial facilities in normal operation, and only become "non-radial" or "looped" when back-up capabilities are required. Accordingly, while the Commission considers that EDTI should be free to propose such facilities in the context of a SASR as part of its duty to reliability operate its distribution system, the Commission likewise considers it is reasonable that the costs for the additional reliability obtained by EDTI through the "looping" provided by the normally open breaker configuration should be considered to be participant-related.

556. For all of the above reasons, the AESO's proposed subsections 4.2(2) and 4.2.(4) as replacements for the corresponding provisions found in subsections 8.3(2) and 8.3(3) of the currently ISO tariff are approved.

#### 7.2.5.5 Use of RCN valuation for facilities reclassified from system to participant

557. EDTI noted that the AESO's proposed subsection 4.2(2)(l) replaces the existing tariff's subsection 8.3(2)(m) and addresses situations where existing system transmission facilities are reclassified to participant-related in order to meet the requirements of a connection project.

558. The relevant provisions are reproduced below as follows:

AESO proposed	Currently approved
4.2(2)(l) the replacement cost new, which is the current cost of similar new equipment having the nearest equivalent capability to the equipment being valued, of existing <b>system transmission facilities</b> that have been reclassified as participant-related to meet the requirements of the connection project;	8.3(2)(m) facilities previously classified as system-related under subsection 3(3)(c) below and now reclassified as participant-related to meet the requirements of the connection project

Source: Exhibit 22942-X0550, EDTI final argument, paragraph 49.

559. EDTI noted that the new provision (subsection 4.2(2)(l)) adds language that did not exist in the current tariff's subsection 8.3(2)(m) that values the reclassified facilities at replacement cost new.

560. EDTI argued that the use of RCN valuation assigns an excessive cost to the market participant by not taking into account depreciation. EDTI submitted that because this provision

could cause excessive costs to be assigned to the market participant, and because the AESO provided no rationale for this change, the proposed provision should be rejected.<sup>605</sup>

561. The AESO responded that its proposal in subsection 4.2(2)(l) is reasonable because:

- the RCN requirement ensures that the estimated cost of existing facilities that are reclassified as participant-related can be compared to new facilities on an equivalent basis
- Subsection 8.5(2)(a) of the AESO's existing tariff terms and conditions already requires the cost of replacement transformers to be valued on an RCN basis for connection project cost determination purposes.<sup>606</sup>

### Commission findings

562. The Commission accepts the AESO's submission that the proposed language in subsection 4.2(2)(l) is required to facilitate an equivalent comparison between old and new facilities, and that it is consistent with the use of a replacement cost new basis to value the cost of replacing existing transformers on an RCN basis. The AESO's proposed subsection 4.2(2)(l) is approved.

#### 7.2.5.6 Advancement of cost classification provisions

563. EDTI was critical about a number of provisions in the proposed ISO tariff related to the classification of the costs of system projects that a market participant wishes to advance.

564. EDTI provided the following summary of the provisions of interest, comparing the AESO's proposed provisions with the corresponding provisions in the currently approved ISO tariff:

AESO proposed	Currently approved
4.2(3) If the <b>ISO</b> identifies system <b>transmission facilities</b> , being <b>transmission facilities</b> that are required by the <b>ISO</b> and that the <b>ISO</b> determines will benefit many <b>market participants</b> , as being required to accommodate a <b>market participant's</b> new or increased Rate DTS capacity, then the <b>ISO</b> must classify the following costs as participant-related:	8.3(2) Participant-related costs... [include] costs associated with: ... (l) the advancement of <b>transmission facilities</b> included as part of a critical transmission development or regional <b>transmission system</b> project under subsection 3(3)(b) below, calculated as the difference between the present values of the capital costs of the advanced and the as-planned facilities using the discount rate provided in subsection 11 below; ...
(a) advancement costs, which are the costs associated with the advancement of system <b>transmission facilities</b> required to accommodate the connection project requesting demand transmission service, which the <b>ISO</b> calculates, using the discount rate provided in subsection 4.9 below, as:	8.3(3) System-related costs ... [include] ... costs associated with: ...
(i) if the system <b>transmission facilities</b> are not included in an approved <b>needs identification document</b> , the difference between the cost of the applicable system <b>transmission facilities</b> and the calculated future value of the system <b>transmission facilities</b> , based on a 5 year period;	(b) radial <b>transmission facilities</b> which, within five (5) years of <b>commercial operation</b> , are planned to become looped as part of a critical transmission

<sup>605</sup> Exhibit 22942-X0550, EDTI argument, paragraph 52.

<sup>606</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(e).

AESO proposed	Currently approved
<p>(ii) if the system <b>transmission facilities</b> are included in an approved <b>needs identification document</b> and do not have a set in-service-date, the difference between the cost of the applicable system <b>transmission facilities</b> and the calculated future value of the system <b>transmission facilities</b>, based on a 5 year period; or</p> <p>(iii) if the system <b>transmission facilities</b> are included in an approved <b>needs identification document</b> and have a scheduled in-service date that can be advanced, the difference between the present value of the capital costs of the advanced and the planned facilities for the number of <b>months</b> that the in-service date will be advanced;</p> <p>and</p> <p>(b) avoidable construction costs, which are the net costs associated with maintaining, at the <b>market participant's</b> request, the in-service date for system <b>transmission facilities</b>, currently under construction, and which the <b>ISO</b> determines could be avoided by delaying the completion of construction.</p>	<p>development or regional <b>transmission system</b> project:</p> <p>(i) in the <b>ISO's</b> most recent long-term <b>transmission system</b> plan;</p> <p>(ii) in a <b>needs identification document</b> filed with the <b>Commission</b>; or</p> <p>(iii) as the <b>ISO</b> reasonably expects will be required in the future;</p>

### EDTI concerns with proposed subsection 4.2(3)(a) (Discretion with regard to advancement cost provisions)

565. EDTI argued that although the currently approved subsection 8.3(2)(l) vests the costs of advancing transmission facilities with the market participant requesting the advancement, it is relatively easy for the market participant to identify the facilities to be advanced through available AESO planning documents.<sup>607</sup> However, EDTI submitted that because the proposed subsection 4.2(3) allows the AESO to assess which facilities benefit many market participants on a project-by-project basis, it is more difficult for market participants to identify the extent of their participant-related costs prior to filing a SASR and engaging in the preferred alternative process established in the AESO's proposed subsection 3.4.<sup>608</sup>

566. EDTI submitted that the AESO should be required to specify clear, objective criteria regarding the types of costs that will be subject to advancement cost treatment. In the absence of such criteria, the AESO's proposed subsection 4.2.(3)(a) should be denied in its proposed form.<sup>609</sup>

567. The AESO replied that the underlying premise of EDTI's statement, that is, the identification of participant-related costs prior to filing a SASR, is flawed. There is no way for the market participant to identify the extent of its participant-related costs prior to filing a SASR.

<sup>607</sup> Exhibit 22942-X0550, EDTI argument, paragraph 55.

<sup>608</sup> Exhibit 22942-X0550, EDTI argument, paragraph 56.

<sup>609</sup> Exhibit 22942-X0550, EDTI argument, paragraph 57.

This is because the AESO does not and cannot select preferred alternatives until a SASR has been selected.<sup>610</sup>

568. The AESO further disagreed that additional specification of costs subject to advancement cost treatment is required. As stated in its amended application, it considered both its current approach and its proposed approach to advancement cost classification to be understood by market participants,<sup>611</sup> and argued that there is nothing on the record that suggests otherwise.<sup>612</sup>

**EDTI concerns with proposed subsection 4.2(3)(a)(i) to (iii) (five-year timeframe for advancement cost provisions)**

569. The AESO's proposed subsections 4.2(3)(a)(i)-(iii) set out the requirement for the market participant to pay advancement costs related to system transmission facilities that the AESO has identified under subsection 4.2(3)(a). EDTI took note that advancement costs under subsections (i) and (ii) are calculated on the basis of a five-year term, and that under subsection (i), advancement costs are payable irrespective of whether the AESO has planned for those facilities in an approved NID.<sup>613</sup>

570. The AESO's rationale for the changes in subsections 4.2(3)(a)(i)-(iii) was provided in the application as follows:

This price signal should apply in any case where the AESO's preferred alternative to address a load market participant's SASR requires the advancement of the construction of system transmission facilities to relieve constraints, and not solely when facilities are planned to become non-radial within five years. The AESO considers that "advancement" occurs both when there is a plan in place to address future congestion or constraints, or where future facilities have never been contemplated to address a forecasted area constraint. Consequently, the AESO proposes that advancement costs apply to all demand connections that trigger the requirement for system transmission facilities to be built to accommodate a demand connection.<sup>614</sup> [emphasis in original]

571. Considering this explanation, EDTI agreed that it is reasonable for a market participant to bear the costs of expanding facilities that benefit only one participant. However, EDTI argued that the provisions appear to grant the AESO discretion to identify potential new system facilities when considering a market participant's SASR. Consequently, the AESO could make a decision that new facilities benefiting many market participants should be constructed, and then charge the market participant submitting the SASR advancement costs, despite the fact that the AESO had never previously conceived of the system project.<sup>615</sup>

572. EDTI contended that the uncertainty arising from the above scenario is exacerbated by the fact that the advancement costs are calculated on the basis of a five-year advancement, even when the proposed system advancement is not scheduled to take place within that window, or is not scheduled at all. EDTI submitted that advancement costs should instead be determined based

<sup>610</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(f).

<sup>611</sup> Exhibit 22942-X0163, Amended application, paragraph 262, PDF page 67.

<sup>612</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(g).

<sup>613</sup> Exhibit 22942-X0550, EDTI argument, paragraph 58.

<sup>614</sup> Exhibit 22942-X0163, Amended application, paragraph 263.

<sup>615</sup> Exhibit 22942-X0550, EDTI argument, paragraph 60.

on when the AESO would require the system facilities to be in place in the absence of the market participant's request.<sup>616</sup>

573. Given that it will have the effect of vesting an indeterminate and unknowable portion of hypothetical system costs on market participants, EDTI submitted that subsection 4.2(3)(a)(i)-(ii) should be denied in their proposed form.<sup>617</sup>

574. The AESO disagreed that its proposed subsection 4.2(3)(a)(i)-(iii) creates uncertainty for a market participant. It argued that EDTI's position ignores the fact that the AESO would select its preferred alternative in response to a SASR based on the lowest overall long-term cost. Accordingly, where the preferred alternative depends on either a system transmission project or a system-related component, the AESO applies advancement costs if the ISD for the system component made necessary by the connection project is later than the ISD requested by the market participant.<sup>618</sup>

575. The AESO added that a market participant can avoid payment of the advancement costs by reducing its requested contract capacity to a level that allows it to connect on an unconstrained basis.<sup>619</sup>

576. The AESO agreed that advancement costs should be based on when the AESO would require system transmission facilities in the absence of the market participant's system access request. It therefore determined that advancement costs payable under subsection 4.2(3)(a)(i)-(iii) should be limited to a maximum five-year timeframe, a period chosen to align with the AESO's typical five-year planning window for system projects.<sup>620</sup> The AESO noted that limiting advancement costs to five years shields market participants from the potential that they could be charged for up to 20 years of advancement costs.<sup>621</sup>

**EDTI concerns with proposed subsection 4.2(3)(b) (lack of clarity with respect to “avoidable construction costs”)**

577. EDTI argued that “avoidable construction costs” is not a defined term. Although the interpretation of subsection 4.2(3)(b) provided by the AESO in its application suggests that the AESO considers that “avoidable construction costs” are costs that could be forgone with “no system impact,” the AESO should make this intention clear by making this express within in its terms and conditions. However, as this is not the case, EDTI submitted that subsection 4.2(3)(b) should be denied in its current form.<sup>622</sup>

578. The AESO rejected EDTI's position that a definition of “avoidable construction costs” was required arguing that the definition is clear on its face from the language in subsection 4.2(3)(b).

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<sup>616</sup> Exhibit 22942-X0550, EDTI argument, paragraph 62.

<sup>617</sup> Exhibit 22942-X0550, EDTI argument, paragraph 63.

<sup>618</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(h).

<sup>619</sup> Exhibit 22942-X0163, Amended application, paragraph 266, PDF page 68, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 161(h).

<sup>620</sup> Exhibit 22942-X0163, Amended application, paragraph 264, PDF pages 67-68.

<sup>621</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 161(i).

<sup>622</sup> Exhibit 22942-X0550, EDTI argument, paragraph 65.

## Commission findings

### Subsection 4.2(3)(a)

579. The Commission considers that it is reasonable for the AESO to have broad discretion with respect to the exercise of its duties, including in the assessment of the effect of market participant system access service requests on the need to undertake other upgrades to the transmission system.

580. Further to the Commission's findings in Section 7.2.3, the Commission considers that the tying of critical information to system access service requests is central to the AESO's proposals for ensuring that the AESO has accurate and timely information for its system planning duties. Accordingly, in respect of the AESO's proposed subsection 4.2(3)(a), the Commission agrees with the AESO that because the assessment of system impacts should be tied to the critical information contained in the market participant's system access service request, EDTI's premise that it should be able to determine definitively the extent of participant-related costs prior to filing a SASR is flawed.

581. While the Commission considers that the AESO should assist market participants in preparing system access service requests prior to filing, and should act reasonably in this regard, the Commission considers that the determination of the full impact of a SASR depends on the specific critical information provided by the market participant.

582. With respect to EDTI's concerns with the AESO's proposed subsection 4.2(3)(a)(i)-(iii), consistent with other findings in this decision, the Commission does not share EDTI's concern that the proposed provision will allow the AESO to assign costs to a market participant that the AESO had never identified prior to the market participant's system access service request.

583. The Commission finds that the AESO's proposal set out in subsection 4.2(3)(a)(i)-(iii) to limit the exposure to advancement costs of a project to no more than five years is reasonable. This period corresponds with the AESO's five-year planning window, recognizes the AESO's system planning obligations as set out in Section 8 of the *Transmission Regulation* and is a reasonable period of time as compared to the AESO's 20 year planning requirement in Section 10 of the regulation.

584. In view of this, the AESO's proposed subsection 4.2(3)(a)(i)-(iii) is approved.

### Subsection 4.2(3)(b)

585. The Commission finds that the proposed wording of subsection 4.2(3)(b) does not require there to be an additional definition for the term "avoidable construction costs" as the provision already defines the term. It is approved.

## 7.2.5.7 Effect on classification of project initiatives by AESO or market participant

### General concerns with classification based on initiation

586. EDTI argued that a determination by the AESO that a project is a system transmission project essentially ends the matter of classifying costs as between system-related and participant-related. As such, the way in which the AESO makes this initial determination as between

whether a specific project is a system or connection project is a vital component of how the AESO operationalizes its customer contribution policy.<sup>623</sup>

587. In AESO-EDTI-2018NOV01-005 and AESO-EDTI-2018NOV01-006,<sup>624</sup> EDTI asked the AESO several questions that compared and contrasted the West Edmonton Area Project (West Edmonton Project) considered by the Commission in Proceeding 23943 with the Downtown Calgary 138 kV Transmission System Reinforcement Project (Downtown Calgary Project), which was considered by the Commission in Proceeding 21038. The referenced IRs sought clarifications of the basis on which the AESO determined that the Downtown Calgary Project, initiated by the AESO as a system transmission project, was classified as system-related, whereas the West Edmonton Project, initiated by EDTI through a SASR, was classified as participant-related.

588. EDTI submitted that in light of the substantial changes to the terms and conditions related to its customer contribution policy, it is of concern that the AESO does not have any clearly defined or consistently applied criteria to determine whether a specific project is a “system” project or a “customer” project. EDTI referenced the Proceeding 22942 record through EDTI’s examination of the Downtown Calgary Project during the oral hearing and information requests as an example of this deficiency.<sup>625</sup>

589. EDTI argued that the AESO’s witness, Ms. Kerr, explained that the AESO initiates system transmission projects, and that because of this, there is no criteria to determine whether an AESO-initiated system project is a system project or a connection project. EDTI further noted Ms. Kerr explained that when a market participant submits a SASR to the AESO, the AESO often “doesn’t see the project coming.”<sup>626</sup> Ms. Kerr contrasted this with the fact that the AESO’s planning is focused on transmission system reliability and is unrelated to any process within the connection process.<sup>627</sup>

590. EDTI submitted that based on Ms. Kerr’s comments, if a market participant files a SASR, the project is a connection project.<sup>628</sup> EDTI stated that a classification framework based on who initiates the project is untenable because it penalizes market participants that would otherwise qualify for system-related treatment solely based on initiation.<sup>629</sup> It argued that who initiates a transmission reinforcement project should be entirely irrelevant to the ultimate treatment of the costs associated with the project as system or participant-related. Instead, the determination should be based on clear, objective technical criteria that all market participants can look to for clear guidance, and can rely on.<sup>630</sup>

591. In reply, the AESO explained that while EDTI “appears to be flummoxed”<sup>631</sup> by the idea that the system transmission projects are distinguished simply based on which entity, as between the AESO and the market participant, initiates the project, this is fundamentally how the

<sup>623</sup> Exhibit 22942-X0550, EDTI argument, paragraph 107.

<sup>624</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005 and AESO-EDTI-2018NOV01-006, PDF pages 7-16.

<sup>625</sup> Exhibit 22942-X0550, EDTI argument, paragraph 106.

<sup>626</sup> Transcript, Volume 2, page 317.

<sup>627</sup> Transcript, Volume 2, pages 316-317, cited at Exhibit 22942-X0550, EDTI argument, paragraph 60.

<sup>628</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-009(d), cited at Exhibit 22942-X0550, EDTI argument, paragraph 110.

<sup>629</sup> Exhibit 22942-X0550, EDTI argument, paragraph 110.

<sup>630</sup> Exhibit 22942-X0550, EDTI argument, paragraph 111.

<sup>631</sup> Exhibit 22942-X0578, paragraph 156.

determination must be made. Further, it submitted that this determination is in accordance with subsections (a) and (b) of Section 34(1) of the *Electric Utilities Act*, which requires the AESO to determine whether it should initiate a system transmission project based on whether the project benefits most or all market participants rather than a single market participant. In this regard, the AESO submitted that projects that the AESO classifies as participant-related are facilities that would not exist but for the distinct request for new or additional system access service through a market participant's system access service request.

### Classification of AESO Downtown Calgary Project

592. EDTI submitted that in responses to its information requests about the Downtown Calgary Project,<sup>632</sup> the AESO confirmed that the project was classified by the AESO as a system project rather than a connection project for the following reasons:

- It was required to meet the needs of many market participants.<sup>633</sup>
- It was required to reinforce a “multi-looped system” providing looped flows into downtown Calgary.<sup>634</sup>
- The need for the project was driven from a regional forecast rather than a SASR or POD need.<sup>635</sup>
- The project assists with the overall reliability of the AIES.<sup>636</sup>
- The project will provides service and support supply to numerous POD substations in the area.<sup>637</sup>

593. EDTI argued that some of the information provided by the AESO in its IR responses was inconsistent with rationale provided by the AESO in the NID application documents supporting the Downtown Calgary Project. Specifically, based on such analysis, EDTI noted the following inconsistencies:

- The NID application and supporting documents such as planning studies did not identify benefits arising from the project other than those accruing to ENMAX DFO.<sup>638</sup>
- In contrast to the AESO's characterization of project in its IR response supporting “numerous POD substations in the area,” the NID application documents only identify the need in relation to three ENMAX DFO substations.<sup>639</sup>
- The NID and associated planning study did not identify any constraints other than those related to the three ENMAX substations.<sup>640</sup>
- A technical document (TPL-002-AB1-0)<sup>641</sup> explicitly referenced in the NID application as supporting the need for the project includes a statement suggesting that constraints under

<sup>632</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005 and 006.

<sup>633</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005(a).

<sup>634</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005(a)(ii).

<sup>635</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005(a)(ii).

<sup>636</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005(a)(ii).

<sup>637</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005(a)(ii).

<sup>638</sup> Exhibit 22942-X0550, EDTI argument, paragraph 116, first bullet.

<sup>639</sup> Exhibit 22942-X0550, EDTI argument, paragraph 116, second bullet.

<sup>640</sup> Exhibit 22942-X0550, EDTI argument, paragraph 116, third bullet.

<sup>641</sup> Exhibit 22942-X0490,



n-1 conditions do not need to be alleviated, suggesting on its face that the Downtown Calgary Project did not need to be assessed by the AESO as a system project.<sup>642</sup>

594. In addition to the above, EDTI submitted that there appears to be significant confusion as to whether and how Alberta Reliability Standards such as TPL-002-AB1-0 are used for the purpose of determining whether a project should be a system project or a connection project. In this regard, EDTI noted that the AESO's witness, Mr. Sullivan, indicated in response to questions that TPL-002-AB1-0 was not a factor in determining whether the project is a system or customer project yet the NID application specifically refers to TPL-002-AB1-0 as being relevant to the project.<sup>643</sup>

595. EDTI explained it raised the Downtown Calgary project in the ISO tariff proceeding to identify that there is a lack of clarity, transparency and predictability in the current process used by the AESO.<sup>644</sup> In this regard, EDTI submitted that Mr. Sullivan eventually stated that the content of NID applications can vary from project to project depending on the specific planner involved.<sup>645</sup>

596. In light of its concerns regarding the lack of clarity regarding the decision to initiate a system project or require a connection project, EDTI requested that the Commission direct the AESO to:

- develop and publish a detailed list of the specific criteria the AESO relies on in determining whether a project is a system project versus a connection project, and file it with the Commission for review and approval; and
- ensure that in its NID applications and supporting documents, the AESO fully describes the factors it had regard for in determining that a project is a system project as opposed to a connection project, with reference to the list of specific criteria.<sup>646</sup>

597. In reply, the AESO conceded that its NID application for the Downtown Calgary Project did not specify the particular regional and overall reliability benefits of the project that were identified by the AESO in its response to AESO-EDTI-2018NOV01-005 and 006.<sup>647</sup> However, the AESO noted that it had adopted those responses as the evidence of the AESO in this proceeding. In addition, the AESO noted that Mr. Sullivan testified to the fact that project provides the benefits identified in the responses.<sup>648</sup>

598. The AESO added that EDTI appears to have equated the use of the term "local transmission network" as used in the Downtown Calgary project NID with the term "local network" in a footnote to TPL-002-AB1-0. However, the AESO noted that Mr. Sullivan had confirmed at the hearing that TPL-002-AB1-0 is not used for the purposes of determining whether a project is a system transmission project or a connection project.<sup>649</sup>

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<sup>642</sup> Exhibit 22942-X0550, EDTI argument, paragraph 116, fourth bullet.

<sup>643</sup> Exhibit 22942-X0550, EDTI argument, paragraph 116, fifth bullet.

<sup>644</sup> Exhibit 22942-X0550, EDTI argument, paragraph 117.

<sup>645</sup> Transcript, Volume 2, page 328, cited at Exhibit 22942-X0550, EDTI argument, paragraph 117.

<sup>646</sup> Exhibit 22942-X0550, EDTI argument, paragraph 120.

<sup>647</sup> Exhibit 22942-X0291, AESO-EDTI-2018NOV01-005 and 006, PDF pages 8-19.

<sup>648</sup> Transcript, Volume 2, pages 335- 338.

<sup>649</sup> Transcript, Volume 2, page 334, lines 19-21.

599. The AESO reiterated that:

the fundamental criteria for determination of a project as either a system transmission or connection project is set out in section 34 of the EUA. In the case of a connection project, there are additional criteria to delineate between participant-related and system-related costs, in order to provide the market participant who has requested system access service with clarity regarding the costs that will be attributed to them. However, there is no need to do so in the case of a system transmission project, because a system transmission project does not involve a distinct system access service request to which the AESO is required to respond.<sup>650</sup>

### Commission findings

600. The Commission agrees with the AESO, that the fundamental criteria for the determination of whether a project is designated as a system project and consequently, the costs for the project are similarly categorized, is dictated by Section 34 of the *Electric Utilities Act*. That provision specifically requires the AESO to make the determination as to whether an expansion or enhancement to the system is required. Further, Section 11 of the *Transmission Regulation* sets out the criteria that the AESO must comply with in its NID submission.

601. Consequently, it is reasonable for the AESO to approach this characterization from the starting point that if it initiates the project pursuant to its responsibilities under the legislation, the project costs would be system-related.

602. The issue of classifying project costs as system-related or participant-related has been the subject of past findings. In Decision 2005-096, the Commission's predecessor stated:

With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be "shades of grey" in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.

The Board does not wish to take away the AESO's discretion under Article 9.11 of its proposed T&Cs to deem costs normally designated as customer costs to be system-related costs in appropriate circumstances. The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the *Transmission Regulation*.<sup>651</sup>

603. Notwithstanding, the Commission acknowledges EDTI's argument that the Downtown Calgary Project received system-related classification treatment that was not afforded to EDTI's West Edmonton Project by virtue of the AESO's initiation of the Downtown Calgary Project as a system transmission project.

604. The Commission considers that EDTI's examination of these projects illustrates that there may be a need to establish clearly defined criteria in order for all parties to understand

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<sup>650</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 157.

<sup>651</sup> Decision 2005-096, PDF page 53.

under what circumstances the AESO may determine a system need and initiate a system transmission project as opposed to when the DFO must put forth the request.

605. Further, the Commission notes that the capital funding mechanism approved for the second generation of performance based regulation fixes capital allowances by way of the K-bar mechanism. As a result, DFOs are incented to seek to have projects classified as system related to avoid costs that would otherwise have to be funded within the DFO's fixed capital funding allowance.

606. Accordingly, the development of this criteria by the AESO will assist in providing further certainty to DFOs regarding what criteria must be met before a project is considered by the AESO to be a system project.

607. The Commission directs the AESO to work with the DFOs to develop an objective set of criteria for the initiation of system transmission projects reflecting the Commission's findings in this decision.

608. The AESO is directed to provide a report on the status of such discussions, including a discussion of any criteria the AESO would propose for determining "grey area" system projects at the time of its next comprehensive GTA. The AESO's proposed changes to its tariff approved in this decision are not suspended pending the development of this criteria.

### **7.3 Distribution connected generation and AESO adjusted metering practice**

609. On May 3, 2018, the AESO released ID 2018-019T in response to its developing concern that the significant increase in the amount and size of distribution connected generation (DCG), including a substantial volume of intermittent DCG attributable to wind and solar, was eroding DTS load billing determinants and creating an uneven playing field between DCGs and transmission connected generation. The AESO prepared ID 2018-019T to provide additional clarity regarding the point of supply and point of delivery at which it applies Rate STS and Rate DTS respectively, and the appropriate contract capacity for Rate STS and Rate DTS for a DFO at a substation. The AESO included an implementation plan within ID 2018-019T that set May 15, 2018 as the date on which the changes would take effect.

610. The AESO described its adjusted gross metering practice in ID 2018-019T as follows:

- The DFO contracts for system access service under Rate STS based on the sum of the feeder flows into the bus.
- The DFO contracts for system access service under Rate DTS based on the coincident sum of the feeder flows out of the bus.
- Demand under Rate DTS and supply under Rate STS would be metered such that flows are not totalized at the POD.
- Separately metered STS and DTS flows and associated STS and DTS contract capacity levels would be used for:
  - calculating and collecting the generating unit owner's contribution (GUOC)
  - making calculations for construction contribution decisions (CCDs)
  - assessing POD charges
  - assessing bulk/regional charges

- The AESO will complete planning studies for a SASR submitted by a DFO requesting system access service under Rate STS where the inflow onto the transmission system is greater than 5 MW.
- The AESO would treat a distribution-connected generator the same as a transmission-connected generator for any remedial action scheme (RAS) requirements.<sup>652</sup>

611. On August 17, 2018, the AESO filed an amendment to its 2018 ISO tariff application. In subsection 7.3.2 of its amended application, the AESO explained that it had proposed a number of changes and clarifications related to the required contract capacity for Rate STS and Rate DTS for a DFO at a substation to reflect an overall increase in distribution connected generation (DCG) projects and an increase in the number of SASRs that the AESO was receiving from DFOs for system access under Rate STS.<sup>653</sup>

612. The AESO noted that, as of May 1, 2018, there were about 1200 MW of DCG projects in the AESO's project list, some of which approached approximately 70 MW in size. In light of the increasing number and size of DCG projects, the AESO indicated that "[t]he impact of these projects is highlighting a number of areas where the current ISO tariff does not have enough clarity, and that historical application of some provisions does not work for large amounts of and large sized distribution-connected generation."<sup>654</sup>

613. The AESO submitted that its proposed adjusted metering practice should be approved because the conditions that led to the current metering practice in Decision 2000-1<sup>655</sup> no longer apply, and because the ability to offset DTS by STS allows DFO substations to enjoy free usage of the transmission system. In addition, the AESO submitted that the current net metering practice caused inaccurate assessments of contract levels and metering levels leading to improper calculation of:

- GUOC payments
- DTS billing determinants
- substation fractions
- investment levels
- POD charges

614. In its view, all of this leads to significant erosion of DTS billing determinants.<sup>656</sup>

615. On October 2, 2018, the Commission issued a ruling confirming that the content of ID 2018-019T was captured within the scope of the AESO's amended tariff application and it was suspending the operation of ID 2018-019T.<sup>657</sup>

616. In its evidence, the CCA provided a general description of the AESO's adjusted metering proposal as follows:

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<sup>652</sup> Exhibit 22942-X0201, PDF page 2.

<sup>653</sup> Exhibit 22942-X0163, paragraph 208.

<sup>654</sup> Exhibit 22942-X0163, paragraph 208.

<sup>655</sup> Decision 2000-1: ESBI Alberta Ltd., 1999/2000 General Rate Application, Phase 1 and Phase 2, Application 990005-1, February 2, 2000.

<sup>656</sup> Exhibit 22942-X0558, AESO argument, paragraph 54.

<sup>657</sup> Exhibit 22942-X0207.

In essence, a DCG connecting to the point of delivery (POD) would be responsible for costs associated with an STS contract including local interconnection costs and GUOC. The effect of these proposals is to mitigate rate impacts to customers arising from load defections associated with addition of DCG.<sup>658</sup>

617. Argument or reply submissions addressing the AESO's proposed adjusted metering practice were filed by:

- AltaLink<sup>659</sup>
- ATCO Electric
- CGWG<sup>660</sup>
- CCA<sup>661</sup>
- DGWG<sup>662</sup>
- ENMAX<sup>663</sup>
- Fortis<sup>664</sup>
- Greengate<sup>665</sup>
- Métis Nation of Alberta (reply argument only)<sup>666</sup>
- Solar Krafte<sup>667</sup>
- U of A<sup>668</sup>

618. With the exception of AltaLink, these interveners opposed the AESO's proposed change.

619. Consideration by the Commission of the issues raised in these submissions and the AESO's response is provided under separate headings below.

### 7.3.1 AESO rationale for proposing adjusted metering practice

620. The AESO explained that although it was reasonable in the past to apply totalized billing of load to distribution substations constructed to serve load, the recent increase of DCG creates the risk for a large erosion of the DTS load billing determinants due to totalizing of demand and supply at the DFO POD level. It also explained that its decision to pursue its proposed adjusted metering approach was also due to concerns that:

- (a) There should be consistent and fair treatment between transmission and distribution-connected generation. Generally, whether generation connects to the transmission system or the electric distribution system, the impact on and the benefits received from the transmission system are the same. Similarly, the AESO considers that there should be no economic advantage that can be achieved by a generator that connects

<sup>658</sup> Exhibit 22942-X0335, paragraph 9.

<sup>659</sup> Exhibit 22942-X0555 (argument) and Exhibit 22942-X0575 (reply)

<sup>660</sup> Exhibit 22942-X0560, CGWG argument, and Exhibit 22942-X0574, CGWG reply argument.

<sup>661</sup> Exhibit 22942-X0549, CCA argument.

<sup>662</sup> Exhibit 22942-X0562, DGWG argument.

<sup>663</sup> Exhibit 22942-X0547, ENMAX argument, and Exhibit 22942-X0571, ENMAX reply argument.

<sup>664</sup> Exhibit 22942-X0559, Fortis argument, and Exhibit 22942-X0579, Fortis reply argument.

<sup>665</sup> Exhibit 22942-X0570, Greengate reply argument (Note: Greengate filed both argument and reply submissions, but only addressed issues related to distribution connected generation in Section 3 (PDF pages 7-9) of its reply argument.

<sup>666</sup> Exhibit 22942-X0569, Métis Nation of Alberta, reply argument.

<sup>667</sup> Exhibit 22942-X0548, Solar Krafte argument, and Exhibit 22942-X0566, Solar Krafte reply argument.

<sup>668</sup> Exhibit 22942-X0542, U of A argument.

- to the transmission system versus the electric distribution system, or vice versa. For example, a distribution-connected generator should not receive distribution derived transmission credits (resulting from totalizing Rate DTS and Rate STS), lower GUOC payments, or avoid a transmission RAS by virtue of it being connected to the electric distribution system. Any inconsistent tariff treatment between transmission and distribution-connected generators may lead to “tariff shopping” by generators in some circumstances.
- (b) Cross subsidies occur as current DFO practices flow any DTS billing reduction resulting from the totalizing of DTS and STS at the substation level through to the distribution-connected generation. This cross subsidy paid to distribution-connected generation will ultimately have to be paid for by load through deferral accounts or higher rates and also provides subsidies that are not available to transmission connected generation, thereby creating market distortions.
  - (c) POD transmission facilities and costs, which historically have generally been utilized or incurred for load connections, can now be properly reviewed such that the substation fraction (i.e., substation split between generation and load) at each POD is properly calculated to determine the impact on AESO investment and monthly POD charges.
  - (d) Contract capacity under Rate STS and Rate DTS, as well as the GUOC (which is based on the contract capacity for system access service under Rate STS), should be reflective of the flow of electric energy onto or out of the transmission system (i.e., these flows are not totalized).
  - (e) Inaccurate Rate DTS and Rate STS contract and metering levels will result in poor information being available for forecasting and planning purposes. Feeder-level metering and contracting will assist with getting more accurate information.
  - (f) The clarity the AESO is proposing is only applicable at the substation feeder level where it exits the substation. Beyond this point the totalizing of load and generation on individual feeders could still occur and result in cross subsidies to distribution-connected generation, an erosion of DTS billing determinants and higher DTS rates. While this is beyond the control of the AESO, the AESO believes that all generation should be treated fairly and consistently irrespective of how it is connected. To ensure consistent treatment of all distribution-connected generation to transmission connected generation, the distribution tariffs should be reviewed to ensure consistent treatment.<sup>669</sup>

621. In response to Commission IR AESO-AUC2018NOV01-021, the AESO explained that it adjusted its metering practice for a number of reasons, including in order to:

- reduce or eliminate the erosion of DTS billing determinants caused by DCG;
- reduce or eliminate the subsidy provided to DCG that the AESO considered to be partially enabled by the AESO’s existing metering practice; and
- address AESO concerns that the subsidy provided to DCG provided an unlevel playing field between DCGs and transmission-connected generation.

<sup>669</sup> Exhibit 22942-X0163, paragraph 213.

622. A number of parties provided submissions responding to the AESO's rationale for implementing the proposed adjusted metering process. The Commission has grouped these submissions under the following separate subheadings.

### **Billing determinant erosion and cross subsidy**

623. AltaLink agreed with the AESO that applying certain long-standing tariff provisions will not work in an environment with a large volume of, and large-sized, DCG. Specifically, AltaLink agreed with the AESO's assessment that DCG has the potential to cause a large erosion of DTS load billing determinants and result in cross-subsidization across market participants.<sup>670</sup>

624. AltaLink explained that if billing determinants across the transmission PODs are reduced by DCGs to levels that result in an unfavorable variance relative to the AESO's revenue requirement, the AESO must true-up that variance and collect it from the AESO's load customers. When this true up occurs, a DFO will recover the AESO true-up charges from its load customers. Consequently, there is no reduction to charges or costs.<sup>671</sup>

625. AltaLink further noted that the DCG Inquiry recognized that because DCG increases the two-way electricity flows on distribution systems, its presence typically requires incremental DFO investment.<sup>672</sup> Further, these incremental DFO costs are likely systemized and recovered from all DFO load customers which exacerbates the cross-subsidization issues associated with DCG.

626. The DGWG argued that despite the AESO's claims that load erosion magnifies cross subsidies paid by load customers to the owners of DCG, the AESO was neither able to quantify the amount of the cross subsidy nor able to describe how this affects load customers. The DGWG added that the AESO has acknowledged that the cross subsidy has historically not been material due to the relatively small numbers of DCG installations. Further, due to totalized billing, DCG has not been visible at POD substations.<sup>673</sup>

### **Billing determinant erosion concerns should be addressed as a tariff matter**

627. The CGWG submitted that the AESO's concern with DTS revenue erosion caused by lower utilization of bulk and regional transmission systems should be addressed as a tariff cost allocation matter by ensuring that revenues come from those "fully utilizing the system."<sup>674</sup>

628. The AESO argued that because its concern arose as a result of the current practice of net metering the DFOs that have DCG on their system, this issue cannot be addressed as a tariff matter because the continuation of the existing practice would not address the issue of inaccurate billing determinants being applied. As such, the issue would persist regardless of other changes that could be made to the design of the ISO tariff.

629. The CGWG responded that the rates are not correctly designed if ratepayers are able to avoid costs without providing a benefit to the system. It submitted that another rate structure

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<sup>670</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 285-287.

<sup>671</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 295.

<sup>672</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, paragraph 493, PDF page 121.

<sup>673</sup> Exhibit 22942-X0257, Information Response to AUC, AESO-AUC-2018NOV01-021 PDF Page 44, cited at Exhibit 22942-X0562, DGWG argument, paragraphs 8-9.

<sup>674</sup> Exhibit 22942-X0560, CGWG argument, paragraph 34.

should be proposed, the 12 CP rates should be reduced, and those costs should be reallocated to a different charge. Further, since the AESO is currently consulting on tariff cost allocation in regard to its 2021 ISO tariff application, these issues are more appropriately addressed in that context.<sup>675</sup>

### **Cause of billing determinant erosion**

630. The DGWG submitted that the erosion of DTS billing determinants is likely to be a significant issue in the future for reasons other than the proliferation of DCG. Given statements by the AESO that load erosion is likely to increase exponentially in the future<sup>676</sup> and that transmission rates are forecast to increase over the next 20 years,<sup>677</sup> the DGWG submitted that the economics of behind-the-fence generation is positive to consumers. As well, the DGWG submitted that the potential implementation of the capacity market could expose consumers to even more power delivery costs.<sup>678</sup>

631. The DGWG submitted that the combination of capacity allocation with on peak cost in excess of \$240/MWh<sup>679</sup> and transmission rates above \$40/MWh is already driving “economic incentives to reduce exposure to the grid.” As it is a simple decision to avoid these costs through behind-the-fence generation in light of billing determinant pressures separate from DCG proliferation, it asserted that the AESO should have designed its tariff in an optimal or holistic manner by consulting with its capacity market design team when developing ID 2018-019T, particularly since the capacity market cost for load customers has the potential to equal or exceed DCG credits<sup>680</sup> on a \$/MWh basis.<sup>681</sup>

632. The AESO responded that at no point in the current proceeding did it state that the existing erosion of DTS load billing determinants is a minor or insignificant issue. The AESO also submitted that the DGWG’s statement that the currently proposed capacity market cost allocation will cause industrial loads to “reduce exposure to the grid” due to on-peak capacity costs in excess of \$240/MWh and transmission rates above \$40/MWh<sup>682</sup> constituted new evidence that has no bearing on the issue of whether the adjusted metering practice should be implemented.<sup>683</sup>

### **Adequacy of AESO analysis of billing determinant erosion**

633. The DGWG submitted that because energy production behind the feeder volumes are netted off against load on feeders, the AESO has no visibility of small DCG. While the AESO may have some visibility “from the energy market perspective,” the DGWG submitted that the AESO does “not have visibility from the transmission billing determinant perspective.”<sup>684</sup>

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<sup>675</sup> Exhibit 22942-X0329, paragraph 23, cited at Exhibit 22942-X0574, CGWG reply argument, paragraph 16.

<sup>676</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-021, PDF page 42.

<sup>677</sup> Exhibit 22942-X0163, Amended application, Line 140, Figure 5-2.

<sup>678</sup> Exhibit 22942-X0562, DGWG argument, paragraph 13.

<sup>679</sup> <https://www.aeso.ca/assets/Uploads/TDAG-CCAA-WG-Update-April-15-2019.pdf>, cited at Exhibit 22942-X0562, DGWG argument, paragraph 14.

<sup>680</sup> DCG credits are defined in Section 7.3.7 of this decision.

<sup>681</sup> Exhibit 22942-X0562, DGWG argument, paragraphs 14-15.

<sup>682</sup> Exhibit 22942-X0562, DGWG argument, paragraph 14.

<sup>683</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 71.

<sup>684</sup> Transcript, Volume 2, page 303, line 17, to page 304, line 3, cited at Exhibit 22942-X0562, DGWG argument, paragraph 5.



634. The DGWG submitted that the AESO had done no analysis to determine the specific value and timing of a projected large erosion event including analysis to:

- differentiate load erosion caused by DCG from potential load erosion from other causes
- establish a per year dollar value over the forward period modelled in the transmission rate projection workbook forecast
- quantify the expected incremental \$/MWh cost on remaining customers from the start of the rate erosion phenomenon
- evaluate the timing of the large projected billing determinant erosion based on the existing project queue.<sup>685</sup>

635. The DGWG noted that although the AESO claimed that it modelled the effect of load erosion from existing DCG and expected growth in its long-term plan, this claim is in conflict with the AESO's testimony that it never performed these calculations.<sup>686</sup>

### **Reliance on AESO connection queue as a measure of billing determinant erosion**

636. The DGWG considered the AESO's ID 2018-019T changes to be short-sighted.<sup>687</sup> It noted that the AESO has previously made large scale investments on the basis of data suggesting large scale renewable investments. As an example, it noted that the connection queue for wind generation was used to justify the transmission system need for the SATR project.<sup>688</sup> However, the initial forecasts used to justify the SATR build did not materialize,<sup>689</sup> with the consequence that the project was changed from its initial scope, certain parts of the project were cancelled in their entirety, and the resulting stranded costs were paid by load.<sup>690</sup>

637. The DGWG submitted that in light of the historical tendency that only a percentage of the renewable generation projects in the AESO's connection queue have gone forward, it is short-sighted to make significant changes like those proposed on the basis of an expectation of significant new DCG SASR applications. In addition, the DGWG submitted that the AESO's proposed changes to GUOC timing should create a further disincentive for projects in the queue to be realized.<sup>691</sup>

### **Commission findings**

638. As discussed above, parties questioned the validity of the AESO's rationale on the basis that the AESO has both overstated and failed to adequately analyse the issue. The Commission does not share this view.

639. Although the penetration of DCG has been comparatively limited to date, the Commission is persuaded that the evidence in this proceeding suggests that DCG is growing and is expected to make up a much larger share of Alberta's generation mix.

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<sup>685</sup> Exhibit 22942-X0279, Information response to DGWG, AESO-DGWG-2018NOV01-005, cited at Exhibit 22942-X0562, DGWG argument, paragraph 6.

<sup>686</sup> Transcript, Volume 2, page 309, line 6, to page 310 line 12, cited at Exhibit 22942-X0562, DGWG argument, paragraph 7.

<sup>687</sup> Exhibit 22942-X0562, DGWG argument, paragraph 59.

<sup>688</sup> Exhibit 22942-X0562, DGWG argument, paragraph 54.

<sup>689</sup> Exhibit 22942-X0562, DGWG argument, paragraph 7. Transcript, Volume 2, page 291 lines 11-22.

<sup>690</sup> Exhibit 22942-X0562, DGWG argument, paragraph 55.

<sup>691</sup> Exhibit 22942-X0562, DGWG argument, paragraphs 57-59.

640. The Commission agrees with the AESO's assessment that, in the absence of the adjusted metering practice, generation developers considering whether to connect their projects at distribution or transmission voltages would be influenced by a preference to avoid the local interconnection costs required from the developers of transmission connected generation. The Commission considers that there should be a level playing field between DCG and transmission connected generators. If costs that are reasonably attributable to DCG are not charged to DCG, there would not be a level playing field between DCG and transmission connected generators with respect to transmission tariff costs.

641. The Commission also agrees with the assessments of the AESO and AltaLink that it would be reasonable to conclude that increased DCG proliferation under the AESO's current metering practice caused by the preferential treatment afforded to DCGs under the net metering of DCGs, combined with the fact that net metering reduces DTS billing determinants as compared to the separate gross metering of DTS and STS, can cause a significant erosion of billing determinants.

642. The Commission also agrees with the AESO and AltaLink that the continuation of the current metering practices would result in an increasing cross-subsidy of DCG by DTS load customers.

643. The DGWG points out that the AESO's projections for the SATR project did not materialize as forecast and, therefore, it claims that the AESO's DCG projections are also unreliable. The SATR transmission facilities were constructed in anticipation of significant wind generation project development that did not materialize in full. Even if the Commission were to accept that the AESO's DCG projections may be overstated, on the basis of its reliance on information from DCG proponents and DFOs, the billing determinant erosion specific to DCG proliferation, at even modest levels, must be remedied. Further, the Commission notes that the AESO has completed some analysis and modelling of billing determinant erosion risk to support its forecast.

644. The Commission disagrees with the submission of the CGWG that the Commission should rely on tariff measures other than those arising from the application of the AESO's adjusted metering practice to address billing determinant erosion concerns or that the matter should be deferred until it can be addressed in the AESO's 2021 tariff.

645. In view of all of the foregoing, the Commission considers that there is sufficient concern with respect to billing determinant erosion and resulting cross subsidy by DTS customers to justify the AESO's decision to propose its adjusted metering practice in conjunction with its 2018 ISO tariff application.

### **7.3.2 Procedural fairness issues**

#### **Adequacy of prior consultation**

In argument, the CGWG expressed concern that the AESO had implemented its proposed metering changes without consulting DCGs, the most affected market participant,<sup>692</sup> and without consulting end-use electricity ratepayers.<sup>693</sup>

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<sup>692</sup> Exhibit 22942-X0560, CGWG argument, paragraph 84(a).

<sup>693</sup> Exhibit 22942-X0560, CGWG argument, paragraph 5.

646. The CGWG argued that the AESO's consultation was flawed because:

- the changes were not part of the AESO's consultation for the 2018 ISO tariff during the period between August 2015 and June 2017,<sup>694</sup> and was instead added to the tariff when the AESO filed its amended application<sup>695</sup>
- the changes were only discussed with DFOs<sup>696</sup>
- the AESO only met with DCG developers after the ID 2018-2019T was issued.

647. The CGWG submitted that the AESO's failure to consult with DCG proponents prior to issuing ID 2018-019T in May 2018<sup>697</sup> was significant, because the AESO knew that DFOs would flow through costs arising from its alternative metering proposal and should have known that DCG developers would be the parties most affected.

648. The CGWG claimed that the AESO's lack of consultation occurred despite the fact that the AESO acknowledged that its proposed metering practice would generally have the effect of increasing Rate STS.<sup>698</sup> Further, the CGWG submitted that the Rate STS increase creates the following additional material financial<sup>699</sup> effects on DCGs:

- changes in GUOC payments, DTS billing determinants, and substation fraction calculation;<sup>700</sup>
- changes in the revenue a DCG can earn through DCG credits; and<sup>701</sup>
- increases in construction contribution costs for DCG projects.<sup>702</sup>

649. In its argument, ENMAX submitted that key implications of the AESO's proposed policy are not well understood because of the lack of consultation and late addition of its adjusted metering proposal to the application. ENMAX submitted that matters that are not well understood, including:

- the implications of the fact that the AESO's proposed policy would create STS contracts and substation fractions where none currently exist;
- significant questions about how GUOC should apply to DCG, including how to deal with the potential for splitting and re-splitting PODs as new generators connect; and
- the implications of the fact that the DFO, not the DCG owner, is the market participant at the POD.<sup>703</sup>

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<sup>694</sup> Exhibit 22942-X0024.02, Exhibit 22942-X0253, AESO-AE-2018NOV01-013.

<sup>695</sup> Exhibit 22942-X0164, paragraph 208; see also Exhibit 22942-X0207, paragraph 13, where the Commission stated that "the proposed changes to the amended tariff are consistent with and in many instances, repeat the language verbatim found in ID 2018-019."

<sup>696</sup> Exhibit 22942-X0253, AESO-AE-2018NOV01-013, PDF page 19.

<sup>697</sup> Transcript, Volume 1, page 177 lines 18-22 (Mr. Sullivan).

<sup>698</sup> Transcript, Volume 1, page 174 line 25 to page 175 line 5 (Mr. Sullivan).

<sup>699</sup> Exhibit 22942-X0329, paragraph 64

<sup>700</sup> Exhibit 22942-X0201, ID 2018-019T, page 1, Section 2.

<sup>701</sup> Exhibit 22942-X0329, paragraph 39.

<sup>702</sup> Exhibit 22942-X0331, paragraph 4, cited at Exhibit 22942-X0560, CGWG argument, paragraphs 24-25.

<sup>703</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 10.

650. ENMAX submitted that a cohesive set of policy objectives should be developed before making changes to the ISO tariff to determine the appropriate treatment of an alternative technology such as DCG.<sup>704</sup>

651. ATCO submitted that the AESO's adjusted metering proposal raises several related issues, including a specific concern that the AESO's proposal would create multiple STS contracts where none currently exist, and would create substation fractions at a number of PODs where none currently exist. ATCO stated that the implications of these and other changes have not been fully considered or addressed and should be examined in greater detail before they are implemented in order to avoid any unintended and unwarranted consequences.<sup>705</sup>

652. The AESO responded to the CGWG's consultation-related concerns arguing that it is not required to consult in respect of the ISO tariff.<sup>706</sup> It considered that it was unnecessary to conduct consultation with market participants other than DFOs<sup>707</sup> and added that because its proposed metering practice changes were necessary from both a legislative and FEOC (fair, efficient and openly competitive) perspective, consultations with DCG developers would not have changed its proposal.<sup>708</sup>

653. The AESO explained that the grandfathering proposal set out in its proposal was intended to ensure that affected market participants, including DCGs, would be sufficiently notified of the change.<sup>709</sup> Further, it argued that the concerns of DCG developers have been well represented in the current proceeding and, therefore, the adequacy of the AESO's prior consultation should not prevent the Commission from approving the adjusted metering practice.<sup>710</sup>

654. In its reply argument, Fortis noted that the AESO had confirmed that it did not discuss ID 2018-019T with any DCG operators or proponents prior to its issuance. Fortis also noted the submission of the University of Alberta, who indicated that despite concerns about being materially affected by the implementation ID 2018-019T, they had not had an opportunity to communicate these concerns properly to the AESO or the Commission. Given this, Fortis submitted that the AESO's consultation regarding ID 2018-019T or its proposed adjusted metering practice was wholly inadequate.<sup>711</sup>

### **Failure of certain parties to file evidence**

655. In argument, the AESO noted that despite expressing concerns with the AESO's proposed adjusted metering practice, both ENMAX and Fortis failed to provide supporting evidence. As a result, the AESO submitted that the views of these parties should be disregarded by the Commission.<sup>712</sup>

656. In reply, ENMAX submitted that no evidence beyond ID 2018-019T was required to support its concern that ID 2018-019T contains authoritative information. Further, no evidence

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<sup>704</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 7.

<sup>705</sup> Transcript, Volume 5, page 903, cited at Exhibit 22942-X0553, ATCO Electric argument, paragraph 62.

<sup>706</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 54.

<sup>707</sup> Exhibit 22942-X0253, AESO-AE-2018NOV01-013, PDF pages 19-20.

<sup>708</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 54.

<sup>709</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 54.

<sup>710</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 55.

<sup>711</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 41(e).

<sup>712</sup> Exhibit 22942-X0558, AESO argument, paragraph 72.

beyond that submitted by the AESO was required to demonstrate that DFOs may be required to incur costs or that DFOs would be concerned about any potential inability to recover those costs.<sup>713</sup>

### **Witness qualifications**

657. In argument, the AESO submitted that neither Mr. Peters nor Mr. Whiteside had expertise in electric transmission operations or matters related to transmission system planning. As such, the AESO submitted that no weight should be given to their views on how DCG can benefit the transmission system.<sup>714</sup>

658. The CGWG replied that Mr. Peters is a professional engineer and has significant work experience in many areas of the utility sector, including familiarity with the Alberta electricity system, and Mr. Peters is well suited to provide the evidence he presented.<sup>715</sup>

### **Positional evidence**

659. The AESO submitted that certain parties promoting rejection of the AESO adjusted metering proposal have failed to acknowledge the cross subsidy provided to DCG through continuation of the existing metering practice. The AESO submitted that when assessing the evidence of certain parties, the Commission must take into account the fact that the positions of certain parties reflect the fact that these parties have an interest in the promotion of DCG.<sup>716</sup>

660. In reply, the CGWG submitted that the AESO's allegation that parties representing the interests of DCG and who opposed the adjusted metering practice reflect interest-based positions, without regard for the effects the cross-subsidy has on ratepayers,<sup>717</sup> is without merit. The CGWG submitted that Power Advisory provided principled evidence that DCG credits are strongly supported by rate design principles such as cost causation.<sup>718</sup>

### **Examination of Bull Creek project costs**

661. During the oral hearing, the CGWG submitted a letter that one of its constituents had received from Fortis on a project known as the BluEarth Bull Creek Project (Bull Creek Project). It presented this evidence as an illustrative example of the magnitude of the change in costs that the project proponent would be exposed to had ID 2018-019T been implemented.

662. In argument,<sup>719</sup> the AESO commented on this evidence, noting that Fortis subsequently filed AESO customer contribution decisions related to the Bull Creek Project in response to an undertaking.<sup>720</sup>

663. In light of the late filing of the Bull Creek connection cost and other information, the AESO submitted that it was not able to provide evidence in response. Accordingly, as the late filed evidence related to the Bull Creek Project could be misleading, and has not been tested by

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<sup>713</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 15.

<sup>714</sup> Exhibit 22942-X0558, AESO argument, paragraph 70.

<sup>715</sup> Exhibit 22942-X0574, CGWG reply argument, paragraph 29.

<sup>716</sup> Exhibit 22942-X0558, AESO argument, paragraph 71.

<sup>717</sup> Exhibit 22942-X0558, paragraphs 54 and 71.

<sup>718</sup> Exhibit 22942-X0574, CGWG reply argument, paragraph 6.

<sup>719</sup> Exhibit 22942-X0558, AESO argument, paragraph 95.

<sup>720</sup> Exhibit 22942-X0529, Response to Fortis Undertaking #5, PDF page 113.

the AESO, it argued that the Commission should not consider this evidence to be probative nor should it be relied upon.<sup>721</sup>

664. In reply, the CGWG noted that the Commission provided the AESO's counsel an opportunity to cross examine Ms. Runge with respect to the information that was put on the record regarding the Bull Creek Project and noted that the AESO chose not to seat a rebuttal panel to address this evidence. Given this, and considering that the AESO had opportunities to test and respond to this evidence and did not do so, the CGWG submitted it is now unfair for the AESO to assert that the evidence cannot be relied upon. Accordingly, the CGWG submitted that the Commission should reject the AESO's suggestion that the Bull Creek Project information should not be considered.<sup>722</sup>

### Commission findings

665. The procedural fairness issues raised concern the sufficiency of consultation by the AESO, the failure to file evidence and the weight to be assigned to that evidence.

666. Regarding the first issue, the Commission dismisses parties arguments that it should not consider the AESO's metering proposal on the basis that the AESO did not engage in sufficient consultation prior to filing its tariff amendment.

667. In Decision 2014-242, the Commission provided its findings regarding when the AESO is required to engage in consultations.<sup>723</sup> Section 3 of the *Transmission Regulation* requires the AESO to consult with market participants who are "likely to be directly affected" by the AESO board's approval of the AESO's own administrative costs, costs for provision of ancillary services or the costs of transmission line losses. The AESO's proposed metering proposal does not fall within any of these categories. Consequently, the AESO is correct in its position that it is not required to consult with participants on this matter. Further, in the event that the AESO chooses to consult on an issue, Section 2 of the *Transmission Regulation* provides the AESO with the discretion to determine how that consultation will proceed. Consequently, the AESO has not contravened any legislative provision to consult on this matter prior to filing its amended tariff application.

668. Regardless of whether consultation was conducted by the AESO on this matter, the Commission has provided all parties who consider themselves to be affected by the AESO's metering proposal with an adequate forum to present their positions, evidence and argument on this matter. Similarly, the Commission has not dismissed the evidence presented on the Bull Creek project because the AESO was provided an opportunity to address this evidence during the oral hearing.

669. Regarding the nature of the evidence presented, the Commission has considered the evidence of all parties on the merits of the evidence presented and has not rejected the evidence of any party filing evidence on the basis of the expertise of the person preparing and defending the evidence. In Bulletin 2016-07,<sup>724</sup> the Commission advised parties that it would accept opinion evidence, regardless of whether the witness could meet the requirements to be qualified as an

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<sup>721</sup> Exhibit 22942-X0558, AESO argument, paragraph 96.

<sup>722</sup> Exhibit 22942-X0574, CGWG reply argument, paragraphs 27-28.

<sup>723</sup> Decision 2014-242 paragraph 68.

<sup>724</sup> Bulletin 2016-07, Practice advisory and procedural change – expert witness qualification no longer required, March 24, 2016.

expert. The Commission has considered the evidence presented in this proceeding and assigned weight to that evidence based on that witnesses professional qualifications, specialized knowledge, experience, independence and objectivity.

### 7.3.3 Metering point for DCG

670. The AESO stated that inaccurate assessments of both contract capacity and metering levels for system access service under Rate DTS and Rate STS at substations has occurred due to the totalizing of system access service under Rate DTS and Rate STS at the 138 kV bus level or the high side of the transformer, instead of at the feeder level.<sup>725</sup>

671. The AESO noted that as Rate STS currently applies to system access service at the point of supply, electricity flowing onto the transmission system is calculated and measured at the demarcation point between the transmission system and the applicable electric distribution system. The AESO considers that a distribution feeder energized at 25 kV or less and located within a substation fenced area to be a transmission facility, as defined in the *Electric Utilities Act*.<sup>726</sup>

672. In argument, the AESO noted that it had explained in both its August 29, 2018 letter<sup>727</sup> and in its response to AESO-AUC2018NOV021<sup>728</sup> that its adjusted metering practice was required to align with the definitions of “transmission facility” and “transmission system” in the *Electric Utilities Act*. Specifically, the AESO considered that the *Electric Utilities Act* definitions support the interpretation that the point at which feeders exit a substation is the demarcation point between the transmission system and an electric distribution system. Additionally, the AESO submitted that because section 17(g) of the *Electric Utilities Act* requires the AESO to provide system access service on the transmission system and prepare an ISO tariff, it follows from section 17(g) and the definitions of “transmission system” and “transmission facility” that the point of supply for Rate STS for DCG must be the point at which the electricity from generation enters the transmission system, not a point before or after it enters the transmission system.<sup>729</sup>

673. The AESO noted that the provisions in Section 8 of the current ISO tariff governing the point of delivery for Rate DTS and the point of supply (POS) for Rate STS require separate metering at the POD or POS except where totalization is applied per subsection 13(4) of the tariff. The specific wording is as follows:

8(1) The **ISO** must apply Rate DTS separately at each **point of delivery**, except where Rate DTS applies to totalized **points of delivery** under subsection [4] of section 13 of the **ISO tariff**.

4(1) The **ISO** must apply Rate STS separately at each **point of supply**, except where Rate STS applies to totalized **points of supply** under subsection [4] of section 13 of the **ISO tariff**.

<sup>725</sup> Exhibit 22942-X0163, paragraph 210.

<sup>726</sup> Exhibit 22942-X0163, paragraph 209.

<sup>727</sup> Exhibit 22942-X0194, PDF pages 5-6.

<sup>728</sup> Exhibit 22942-X0257, PDF pages 42-43.

<sup>729</sup> Exhibit 22942-X0558, AESO argument, paragraph 56.

674. The AESO explained that the provision of the tariff addressing totalization set out in subsection 4 of Section 13 does not address the metering point. Accordingly, the ISO tariff is silent on the metering point for DTS and STS.<sup>730</sup>

675. The AESO added that the tariff of the AESO's predecessor (the Transmission Administrator) defined "contract capacity" of a new point of supply to be an amount not exceeding the totalized amount of generation and loads under normal operating conditions.<sup>731</sup> This meant that the point of supply was automatically calculated net of load (i.e., totalized) by definition.<sup>732</sup> Accordingly, because the provisions governing totalization in the AESO tariff were changed from expressly requiring the ISO to apply totalized billing, the AESO submitted that this change also supported the AESO's position that it has discretion to determine that the metering point for system access service should be at the feeders.

676. Fortis responded to two matters in its argument: (i) the AESO's assessment that inaccurate assessments of DTS and STS levels have occurred due to the practice of totalizing at the 138 kV bus level or high side of the transformer rather than at the feeder level; and (ii) the AESO's explanation that its adjusted metering practice reflects the *Electric Utility Act's* definition of transmission facilities.<sup>733</sup>

677. Fortis argued that the definition of "transmission facilities" in the *Electric Utility Act* has not changed since it became law in 1995. Therefore, it is inappropriate for the AESO to now use the same definition to change how it effectively defines a point of delivery and point of supply for purposes of applying the ISO tariff on a go-forward basis.<sup>734</sup>

678. Fortis submitted that in the provision of any utility service, the physical demarcation point between what constitutes transmission versus distribution (or customer related) does not always practically correspond to the location of the metering point. For example, it noted that the Primary Service Credit authorized under the ISO tariff permits the installation of a single large transmission-connected dual-use customer meter and the application of the ISO tariff to the high side of a substation transformer, effectively totalizing both load and generation on the customer's transmission transformer and distribution feeders. Further, Fortis noted that the AESO has confirmed<sup>735</sup> that it is not proposing to apply net billing to industrial complexes. Consequently, because the AESO permits high side metering in other contexts, applying the AESO's proposed adjusted metering practice only to distribution owners and DCGs would result in unfair and discriminatory treatment between transmission and DCGs.<sup>736</sup>

679. The CGWG also noted in reply that the definitions of transmission facility and transmission system have remained unchanged since the *Electric Utilities Act* was brought into effect in 2003. Further, the CGWG submitted that it was not aware that an interpretation of these terms, similar to that now presented by the AESO, had been brought forward in any prior proceedings.<sup>737</sup> Rather, the CGWG submitted that the AESO's position selectively relies on these definitions in an attempt to describe the transmission system as a single entity as well as to

<sup>730</sup> Exhibit 22942-X0558, AESO argument, paragraphs 105-106.

<sup>731</sup> Decision 2000-34, PDF page 34, cited at Exhibit 22942-X0558, AESO argument, paragraph 109.

<sup>732</sup> ISO Tariff, Section 13, Subsection 4, cited at Exhibit 22942-X0558, AESO argument, paragraph 110.

<sup>733</sup> Exhibit 22942-X0559, Fortis argument, paragraph 43.

<sup>734</sup> Exhibit 22942-X0559, Fortis argument, paragraph 44, citing Exhibit 22942-X0206, page 3.

<sup>735</sup> Exhibit 22942-X0311, AESO-FAI-2018NOV01-006 (c).

<sup>736</sup> Exhibit 22942-X0206, pages 3-4, cited at Exhibit 22942-X0559, Fortis argument, paragraph 44.

<sup>737</sup> Exhibit 22942-X0560, CGWG argument, paragraph 9.



support the AESO's view that briefly touching the system is equivalent to utilizing the entire system. Like Fortis, it argued that the AESO's reinterpretation of these terms is inconsistent because industrial complexes would be permitted to utilize totalized metering in certain circumstances.<sup>738</sup>

680. Greengate addressed the AESO's argument that the removal of language in the Transmission Administrator's<sup>739</sup> tariff that had required totalization supported the AESO's change to gross metering.<sup>740</sup> Greengate submitted that if the AESO's rationale for making this change was allowed to stand, it would extend the AESO's authority to make changes to any item not clearly established in the tariff. Granting power to the AESO to change its tariff interpretation at will, even for significant changes that should require Commission approval, would lead to significant market participant uncertainty as to the stability of tariff provisions.<sup>741</sup> Further, Greengate submitted that allowing the AESO's interpretation to stand would provide an incentive to the AESO to adopt non-specific tariff language in order to make significant changes through information documents and avoid consultation.<sup>742</sup>

681. In its reply, Fortis also submitted that it is significant that the AESO has not expressed any concerns regarding consistency with industrial complexes and how metering is done for those market participants.<sup>743</sup>

682. The AESO responded that allowing industrial customers to choose between net or gross STS or DTS metering reflected the fact that industrial complexes, unlike DCG, have combined load and on-site generation and, therefore, should be able to develop their own economic supply of generation to serve their integrated processes in the most economical manner possible.<sup>744</sup> It added that in light of the Commission's decision in Decision 23418-D01-2019,<sup>745</sup> approving an application by EPCOR Water Services Inc. to construct and operate a proposed 12 MW solar power plant primarily to supply EPCOR's E.L. Smith Water Treatment plant, totalization would now appear to be irrelevant or inapplicable for industrial complexes that have not obtained an industrial system designation under Section 4 of the *Hydro and Electric Energy Act*, or that are not otherwise subject to an exemption in respect of the energy produced by the complex.

683. Further, the AESO proposed that in the event that the Commission accepts the AESO's updated position proposed, in its argument as referenced in the above paragraph with respect to industrial complexes, subsections 3.2(2)(f) and 3.6(4) of the proposed 2018 ISO tariff should be revised to provide that an industrial site will only be able to "choose" totalized metering at a substation if an approval from the Commission has been obtained that permits the export of electric energy to the AIES (Alberta Interconnected Electric System).

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<sup>738</sup> Exhibit 22942-X0558, paragraphs 73, 78.

<sup>739</sup> The AESO's predecessor was the Transmission Administrator or TA.

<sup>740</sup> Exhibit 22942-X0588, PDF page 41, paragraph 110, cited at Exhibit 22942-X0570, Greengate reply argument, paragraph 24.

<sup>741</sup> Exhibit 22942-X0570, Greengate reply argument, paragraph 26.

<sup>742</sup> Exhibit 22942-X0570, Greengate reply argument, paragraph 27.

<sup>743</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 41(d).

<sup>744</sup> Exhibit 22942-0558, paragraph 73.

<sup>745</sup> Decision 23418-D02-2018: EPCOR Water Services Inc., E.L. Smith Solar Power Plant, Proceeding 23418, Applications 23418-A001 and A002, February 20, 2019.

## Commission findings

684. Each of Fortis, CGWG and Greengate challenged the AESO’s position that its proposed changes are reflective of the provisions of the *Electric Utilities Act* on the grounds that the terms relied upon by the AESO had not changed since the initial passage of the act and that the AESO’s proposal is discriminatory because it does not apply to industrial complexes.

685. The definition of a “transmission facility” as set out in the *Electric Utilities Act* is as follows:

- (bbb) “transmission facility” means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes
    - (i) transmission lines energized in excess of 25 000 volts,
    - (ii) insulating and supporting structures,
    - (iii) substations, transformers and switchgear,
    - (iv) operational, telecommunication and control devices,
    - (v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from
      - (A) the low voltage terminal,
      - to
      - (B) electric distribution system lines that exit the substation and are energized at 25 000 volts or less,
  - and
  - (vi) connections with electric systems in jurisdictions bordering Alberta,
- but does not include a generating unit or an electric distribution system;  
[emphasis added]

686. The Commission considers that the AESO’s proposal to specify that meters installed on distribution voltage feeder lines that are located within a substation as transmission facilities is compliant with the provisions in the act.

687. Regarding the allegations that the AESO’s position is discriminatory, the Commission accepts the AESO’s view that industrial complexes are different from DCG’s; therefore, to the extent that an industrial complex has obtained an industrial system designation under Section 4 of the *Hydro and Electric Energy Act*, the AESO’s proposed revisions to subsections 3.2(2)(f) and 3.6(4) of the proposed 2018 ISO tariff are approved.

688. The Commission further accepts the AESO’s proposal to revise subsections 3.2(2)(f) and 3.6(4) of the proposed 2018 ISO tariff to provide that an industrial site will only be able to “choose” totalized metering at a substation if an approval from the Commission has been obtained that permits the export of electric energy to the AIES.

689. The Commission rejects Greengate's argument that the AESO would be incented to adopt non-specific tariff language in order to make significant changes through information documents rather than through a tariff that would require Commission oversight.

690. Although, the Commission retains oversight to approve or deny proposed changes of a substantive nature through its review of the ISO tariff, there are other legislative provisions entitling parties to complain to the Commission if they are concerned about the AESO's conduct.

#### **7.3.4 Public interest considerations**

691. A number of parties provided submissions suggesting that the implementation of the AESO's proposed adjusted metering practice would be contrary to the public interest. The Commission discusses these submissions, and the AESO's response, under the separate subheadings below.

#### **Compatibility of adjusted metering proposal with Government renewable generation policies**

692. The CGWG argued that members of CanSIA, ACCA and FNPA have been making significant investments of time and money in the development of renewable DCG in Alberta. It submitted that the AESO's proposed changes will result in stranded investment and will directly prevent the development of community generation.<sup>746</sup> Further, it asserted that the AESO's proposed change to its metering practice does not align with the policy objective of the Alberta government to achieve a generation mix comprising at least 30 per cent renewable generation sources by 2030.<sup>747</sup>

693. The CGWG's witness, Mr. Bateman, considered that the AESO's proposed alternative metering process runs contrary to government policy goals of reducing greenhouse gas emissions and does not recognize the significant decline in the cost of photovoltaics that has taken place over the last decade.<sup>748</sup> The CGWG added that the AESO's witness, Mr. Sullivan, confirmed that the AESO has not done any analysis regarding the effects of its proposed metering change may have on the Government of Alberta's target to achieve 30 per cent renewable power by 2030.<sup>749</sup> Therefore, one cannot be confident that the AESO's chosen solution to its perceived problem is ideal.<sup>750</sup>

694. ENMAX did not support the CGWG's position. It submitted that the ISO tariff must satisfy the requirements of the legislation and regulations and where policy changes are not explicitly reflected in legislation, the AESO is constrained in its ability to achieve such policy objectives.<sup>751</sup> ENMAX contended that there is no basis to not adopt the AESO's proposals based on the CGWG's concern that the AESO's proposed changes will strand investment and will prevent the development of community generation. If subsidies are required to make particular projects viable, that is a matter for explicit government policy, not the ISO tariff.<sup>752</sup>

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<sup>746</sup> Exhibit 22942-X0560, CGWG argument, paragraph 3.

<sup>747</sup> Exhibit 22942-X0560, CGWG argument, paragraph 84(c).

<sup>748</sup> Exhibit 22942-X0505, cited at Exhibit 22942-X0560, CGWG argument, paragraph 37.

<sup>749</sup> Transcript, Volume 1, page 177 lines 1-6 (Mr. Sullivan), cited at Exhibit 22942-X0560, CGWG argument, paragraph 38.

<sup>750</sup> Exhibit 22942-X0560, CGWG argument, paragraph 40.

<sup>751</sup> Exhibit 22942-X0572, ENMAX reply argument, paragraph 27.

<sup>752</sup> Exhibit 22942-X0572, ENMAX reply argument, paragraph 23.

## Lower connection costs

695. The CGWG submitted that the prospect of allowing additional generation capacity to the AIES with minimal investment in additional transmission infrastructure is at the heart of the value delivered by DCG. The CGWG supported this claim in its argument by comparing the cost of connecting the BluEarth Bull Creek wind project at distribution and transmission voltages.<sup>753</sup>

696. Using assumptions and data sources discussed in its argument, the CGWG submitted that the cost of the Bull Creek project was \$463,109 for a distribution voltage connection while the cost of a transmission voltage connection would have been between \$4 million and \$15 million. Relying on its assessment, the CGWG submitted that there is an order of magnitude difference between the cost of connecting at distribution and transmission voltages in this case.<sup>754</sup> The CGWG submitted that by utilizing an existing substation rather than requiring the construction of a new substation, private investment costs are reduced, which can be used in other ways that are more beneficial to the Alberta economy.<sup>755</sup>

697. In addition to the above, the CGWG noted that several sources show that fewer facilities are required to connect DCG as compared to transmission connected generation, thereby benefiting ratepayers. It claimed that this was demonstrated by the following observations:

- 81 greenfield substations between 2000-2017 with capacity between 13.5 and 75.6 MW (consistent with DCG size)<sup>756</sup> had an average participant-related cost of \$407,772/MW<sup>757</sup>
- A portfolio of 11 projects of one DCG developer showed an average DCG connection cost of \$50,171/MW of capacity<sup>758</sup>
- While the AESO disagreed with Mr. Peters' evidence on the typical cost of a transmission project (the AESO noted a range between \$18,000 and \$825,000/MW),<sup>759</sup> the centre of this range (\$421,500/MW) is consistent with Mr. Peters' analysis (\$407,772/MW)<sup>760</sup>
- An AESO IR response provided information that equated to a transmission facility cost of \$367,000/MW.<sup>761</sup>

698. The CGWG submitted that the evidence discussed above shows that DCG is more cost-effective than transmission connected facilities as it utilizes existing infrastructure, thereby lowering costs to ratepayers.<sup>762</sup>

<sup>753</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 12-14.

<sup>754</sup> Exhibit 22942-X0560, CGWG argument, paragraph 14.

<sup>755</sup> Exhibit 22942-X0560, CGWG argument, paragraph 15.

<sup>756</sup> Exhibit 22942-X0003.02, Revised Appendix G – POD Cost Function Workbook.

<sup>757</sup> Exhibit 22942-X0331, paragraph 33, cited at Exhibit 22942-X0560, CGWG argument, paragraph 17(a).

<sup>758</sup> Exhibit 22942-X0331, paragraph 34, cited at Exhibit 22942-X0560, CGWG argument, paragraph 17(b).

<sup>759</sup> Exhibit 22942-X0447, paragraph 103.

<sup>760</sup> Exhibit 22942-X0560, CGWG argument, paragraph 17(c).

<sup>761</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-021 Figure 4 - Scenario 2., cited at Exhibit 22942-X0560, CGWG argument, paragraph 17(d).

<sup>762</sup> Exhibit 22942-X0560, CGWG argument, paragraph 18.

699. Solar Krafte argued that DCG pays a \$/MW cost approximately 250-400 per cent higher than the \$/MW cost paid by transmission connection generation. In support of this proposition, Solar Krafte presented a table showing that:

- two transmission connected generation projects of between 400 and 450 MW had connection costs of \$11,178 and \$11,473 per MW; and
- two DCG projects of between 17.4 and 29.5 MW had connection costs of between \$40,406 and \$59,324 per MW.<sup>763</sup>

700. The AESO replied that connection costs are one of many factors that the proponent of a generation project must incorporate into its economic assessment. As it stated in its rebuttal evidence, the costs associated with connecting a generator at either a distribution or transmission level is irrelevant to the question of whether the AESO's adjusted metering proposal should be implemented.<sup>764</sup> Moreover, any cost effectiveness in favour of DCG underscores why the adjusted metering practice should be implemented in order to reduce cross-subsidization and market distortions so that generation of all types can connect and compete on a more level playing field.<sup>765</sup>

701. ENMAX also disagreed with the CGWG's claim that connection costs and other effects of generating facilities will always be lower for DCG projects.<sup>766</sup>

### **Other benefits from DCG**

702. During the oral hearing, the Commission asked the CGWG witness panel the following question:

Q. I would like to get a bit better idea about the savings that arise as a result of DCG locating at lower cost point. I can't remember who was talking about that. But what I'm interested in is not just the fact that it costs the DCG less to locate at a particular area, but I'm interested in -- I think a phrase was put forward about the benefits that arise for the system as a result of location somewhere. I can't remember if it was line loss or not, but anyway. If you could give me some more information about what I might refer to as an external benefit of that, if that phrase means anything to you, that accrued to the system as a whole as a result of location, that would help me understand a little bit more about what's going on, if there are any.<sup>767</sup>

703. In response, the CGWG submitted that DCG benefits ratepayers by facilitating location of generation closer to load, thereby reducing losses. Furthermore, the CGWG stated that due to competition, any benefits of reduced losses are ultimately captured by ratepayers.<sup>768</sup> The CGWG also submitted that promoting DCG through ISO tariff measures provided benefits by increasing the number of viable generation projects. As with loss-related benefits, the CGWG submitted that competition will ensure that these cost savings are passed to ratepayers.<sup>769</sup>

<sup>763</sup> Exhibit 22942-X0548, Solar Krafte argument, PDF pages 2-3.

<sup>764</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 103, PDF page 31, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 58.

<sup>765</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 58.

<sup>766</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 25.

<sup>767</sup> Transcript, Volume 4, page 772 line 18 to page 773 line 8 (Mr. van Egteren).

<sup>768</sup> Exhibit 22942-X0560, CGWG argument, paragraph 8.

<sup>769</sup> Exhibit 22942-X0560, CGWG argument, paragraph 10.

704. The CGWG submitted that the Alberta economy generally benefits from the fact that savings from the lower cost of connecting DCG rather than building a new substation can be invested elsewhere.<sup>770</sup> In addition, there is a benefit from the fact that the utilization of existing infrastructure reduces the number of affected landowners and corresponding regulatory burden related to dealing with landowner concerns.<sup>771</sup>

705. In reply, the AESO did not dispute the possibility that DCG may provide non-transmission benefits, but disputed the CGWG's claim that DCG provides benefits to the transmission system. To the contrary, the AESO submitted that DCG requires benefits from the transmission system. As discussed in the AESO's response to AESO-AUC-2018NOV01-021,<sup>772</sup> the AESO's rebuttal evidence,<sup>773</sup> and the AESO's argument:

67. DCG requires the support and benefit of the transmission system to supply load, obtains operational flexibility from the transmission system, and cannot be relied upon for transmission system planning purposes; nor is it relied upon for distribution planning purposes, as confirmed by Fortis. DCGs rely upon the transmission system to enter into power purchase arrangements with load customers. DFO point of delivery and point of supply substations would not exist but for the opportunity to benefit from the transmission system (including the bulk and regional components) and to obtain access to the markets that the transmission system enables.<sup>774</sup>

706. The AESO submitted that the lack of transmission system benefits underscores the inappropriateness of the existing metering practice and the DCG credits that the current metering practice enables.<sup>775</sup>

707. In its reply, ENMAX agreed with the CGWG that by facilitating the location of generation sources closer to load, both transmission and distribution system losses can be reduced.<sup>776</sup> ENMAX agreed that building generation closer to load provides loss reduction benefits and explained that this was one of the reasons that ENMAX built the Shepard and Crossfield Energy centres close to the city of Calgary. ENMAX submitted that the fact that its Shepard and Crossfield plants are transmission-connected, not distribution-connected, underscores the fact that the magnitude of any benefits related to a generating unit's location relative to load and other generation is not a function of whether it is connected to the transmission system or a distribution system.<sup>777</sup>

708. ENMAX further submitted that it is highly uncertain that the existing metering practice is the best, or only, way to recognize any possible benefits. Instead, ENMAX submitted that potential mechanisms for recognizing the benefits of DCG should be considered in the

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<sup>770</sup> Exhibit 22942-X0560, CGWG argument, paragraph 15.

<sup>771</sup> Transcript, Volume 4, page 774 lines 2-19 (Mr. Peters), cited at Exhibit 22942-X0560, CGWG argument, paragraph 16.

<sup>772</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-021, PDF pages 43-44.

<sup>773</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 85(f), PDF page 24.

<sup>774</sup> Exhibit 22942-X0558, AESO argument, paragraph 67, PDF page 28.

<sup>775</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 56.

<sup>776</sup> Exhibit 22942-X0560, CGWG argument, paragraph 8, cited at Exhibit 22942-X0547, ENMAX argument, paragraph 24.

<sup>777</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 25.

Commission's Distribution System Inquiry. Accordingly, ENMAX submitted that no changes should be made to the AESO's metering practices until this consideration is undertaken.<sup>778</sup>

709. Solar Krafte argued that providing an incentive for DCG to locate to where there is load growth benefits the AIES by:

- providing an offset to the need to make investments in transmission, or distribution facilities that would otherwise be recovered through rates;
- providing increased electric system reliability;
- reducing the reliance on high-voltage delivery systems that are subject to significant Alberta climatic risks such as high winds;
- facilitating the ability to ride out major outages through islanding;
- providing emergency power supplies;
- reducing peak power requirement;
- reducing line losses;
- providing ancillary services;
- reducing land use effects and lowering right-of-way acquisition costs; and
- reducing vulnerability to terrorism.

710. Solar Krafte further claimed that benefits that are specific to inverter-based solar photovoltaic systems include:

- the ability to provide reactive power up to the nameplate capacity of the generator
- improvement in grid stability through the ability to cancel or mitigate transients in real time;
- improved system stability related to the capability of solar to provide extremely fast ramping;
- capturing daytime only pricing (150 per cent higher than night time low demand periods); and
- providing an ideal profile to match peak summer irrigation and air conditioning load

711. Further, unlike wind generation, solar generation:

- acts as *de facto* peaker generation;
- does not provide power on top of 24/7 cogeneration power at nighttime, when there is low demand; and
- has predictable minimum and maximum generation profiles.

712. Solar Krafte added that expenditures on DCG projects, expected to total over \$500 million, would provide significant direct and indirect economic benefits to southern Alberta. Also, because they are not property tax exempt, the promotion of DCG projects would create significant property tax revenue.<sup>779</sup>

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<sup>778</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 28.

<sup>779</sup> Exhibit 22942-X0548, Solar Krafte argument, PDF pages 5-6.

713. AltaLink replied that no parties had demonstrated that DCG provides quantifiable benefits to the transmission system. In this regard, AltaLink noted the following comments by the Commission in the DCG Inquiry Final Report:

The AUC heard that in Alberta there will be few if any benefits associated with the curtailment of transmission expansion. The backbone transmission system in Alberta has already been built to accommodate growth for many years to come. The roll-out of DCG does not eliminate the costs already incurred and therefore does not reduce rates paid by customers for the transmission system. While there might be some local, lower voltage transmission costs that might be deferred, few participants drew the AUC's attention to those types of costs and certainly no one had any cost estimates of the deferred costs that might be realized. Parties recognized that the value of deferred capacity costs on the transmission system in Alberta would be minimal.<sup>780</sup> [emphasis added by AltaLink]

### Commission findings

714. Parties opposed to the AESO's proposed change to its metering practice argued that this change will stifle growth in renewable DCG contrary to public policy targets and that the AESO has failed to consider the societal and grid system benefits that DCG provides, justifying a continuation of the current metering practice.

715. The *Electric Utilities Act* requires the AESO to "exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity."<sup>781</sup> However, the AESO is not required to apply this provision to proposals under the *Renewable Electricity Act*.<sup>782</sup>

716. The *Renewable Electricity Act* was proclaimed March 31, 2017. In the act, the government target of 30 per cent renewable energy resources by the end of 2030 was legislatively directed. Further, the act enables the minister to direct the AESO "to develop a proposal for a program to promote large-scale renewable electricity generation in Alberta."<sup>783</sup> Following any such direction, the AESO is required to develop the program and submit it to the minister for approval. The act provides further direction concerning the carrying out of the programs.

717. In June 2019, the Government of Alberta advised the AESO that it will not be continuing with the renewable electricity program (REP) and that:

... The AESO's efforts going forward should be focused on proper oversight of the projects and contracts awarded under previous rounds of the program.

Although Alberta will not be continuing with the Renewable Electricity Program, I would like to encourage the AESO to continue to work with the Department of Energy as we

<sup>780</sup> Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry, Final Report, December 29, 2017, paragraph 495.

<sup>781</sup> *Electric Utilities Act*, Section 16(1).

<sup>782</sup> *Electric Utilities Act*, Section 16(2).

<sup>783</sup> *Renewable Energy Act*, Section 3(1)



begin our work to ensure market-driven renewable power, without the need for costly direct subsidy, as party of Alberta's future electricity mix.<sup>784</sup>

718. In view of the government direction noted above, the Commission is not persuaded that the AESO's proposal should not be implemented on the basis that it may affect renewable DCG public policy targets. Further, the Commission considers that the ISO tariff should reflect cost causation principles (discussed in Section 7.3.5 below) related to the transmission system, and that if DCG requires economic support to ensure economic viability then this is a matter for government policy to address, and not the ISO tariff.

719. The CGWG argued that the cost of connecting renewable generation at distribution voltage is less than the cost of connecting generation at transmission voltage and, because of this cost advantage and because it considered that competition in the generation market will result in cost savings to end-use electricity customers, it is of benefit to customers to promote distribution connected generation. However, Solar Krafte, a party with similar interests, suggests in its argument that ISO tariff treatment that promotes DCG is needed in order to counteract the relative connection cost disadvantage on a \$/MW basis of DCG relative to transmission connected generation. Given the apparent inconsistency between the CGWG and Solar Krafte, there is no clear evidence that DCG has a connection cost advantage or disadvantage over transmission connected generation.

720. The Commission is also persuaded by the evidence of the AESO that other asserted benefits are unsupported and that these assertions do not consider the benefits provided from the transmission system. Further discussion of this issue follows below in Section 7.3.5 (cost causation).

### 7.3.5 Cost causation and cost allocation issues

721. In argument, the AESO stated that applying its proposed change to the substation fraction is consistent with the principle of cost causation.<sup>785</sup> Furthermore, the AESO submitted that it is appropriate that DCGs bear partial cost responsibility for transmission line or POD costs designated as participant-related costs in accordance with the AESO tariff through the flow through of such costs by the DFO.<sup>786</sup>

722. The AESO noted that witnesses for the CGWG, Ms. Runge and Mr. Hildebrand, claimed that generation should not be required to pay for prior transmission or distribution upgrades that occur before the generation enters into service,<sup>787</sup> and should not be charged for transmission system upgrades that occur after the generator enters into service.<sup>788</sup>

723. Considering that load, and not generation, pays for system transmission facilities, the AESO assumed that the facilities that Ms. Runge and Mr. Hildebrand referred to as transmission

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<sup>784</sup> Letter by Alberta Energy, dated June 10, 2019. <https://www.aeso.ca/assets/Uploads/GoA-REP-32469signed-letter.pdf>

<sup>785</sup> Decision 2008-111: Russ Duncan, Concept for Distribution System Cost Recovery, Application 1466609-1, page. 10, PDF page 1 4; See also, for example, *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

<sup>786</sup> Transcript, Volume 3, page 450, lines 4-11; Transcript, Volume 1, page 168, lines 9-22, cited at Exhibit 22942-X0558, AESO argument, paragraph 94.

<sup>787</sup> Exhibit 22942-X0504, PDF page 2.

<sup>788</sup> Transcript, Volume 4, page 751, lines 22-25.

system upgrades are transmission connection facilities. However, even with this clarification, the AESO disagreed with the positions advanced by Ms. Runge and Mr. Hildebrand. The AESO argued that insofar as the generator will benefit and make use of the facilities going forward, charging a generator for the use of existing connection facilities is consistent with the principle of cost causation. Similarly, if new facilities, such as a transmission line, are constructed as a consequence of a distribution system owner's need for additional reliability, it cannot be said that the generator will not use or benefit from the new transmission facility.<sup>789</sup>

724. The AESO submitted that the inflow of power at a POD feeder level is used to set Rate STS levels and to calculate the sharing of interconnection costs used in the AESO's substation fraction formula, the inflow is only a proxy to assess the sharing of costs for access and interconnection, whether load or generation, to the transmission system. Accordingly, as explained in the AESO's response to AESO-AUC-2018NOV01-021<sup>790</sup> and in the AESO's rebuttal evidence,<sup>791</sup> it is not just the ability to inflow energy at the POD that provides benefits to DCG from the transmission system. Instead, it is important to recognize that DCG requires the support and reliability of the transmission system in order to supply energy or ancillary services to the markets, which subsequently serves load, including load located beyond the point of a substation feeder.<sup>792</sup>

725. The CGWG argued that the AESO had not done any analysis to determine whether the substation fraction proxy provides a true representation of the benefits received by specific customers.<sup>793</sup> Given this lack of analysis by the AESO, there "can be no assurance that the substation fractioning methodology is an appropriate way to assess benefit."<sup>794</sup>

726. The CGWG referred to the Peters Energy evidence that claimed spending in substations has increasingly been driven by a desire by load (DTS) customers for redundant facilities to enhance reliability.<sup>795</sup> The CGWG submitted that DCG does not derive any meaningful benefits from these reliability enhancements and that it is inconsistent with cost causation principles for DGCs to be required to pay for any of the costs of substation upgrades put in place to address the reliability requirements of load customers.<sup>796</sup>

727. The CGWG added that its Power Advisory analysis showed that a 30 MW Rate STS contract would have the effect under the AESO's adjusted metering proposal of requiring the DCG to pay a cash contribution on a portion of participant-related costs of a substation project,<sup>797</sup> even though these participant-related costs "were not caused by the DCG."<sup>798</sup> It submitted that the participant-related costs considered in the Power Advisory evidence example "are generally the embedded costs of past substation upgrades, which would have occurred with or without the connection of the DCG."<sup>799</sup> The CGWG submitted that this treatment is inconsistent with the

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<sup>789</sup> Exhibit 22942-X0558, AESO argument, paragraph 93.

<sup>790</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01021, PDF pages43-44

<sup>791</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 85(f).

<sup>792</sup> Exhibit 22942-X0558, AESO argument, paragraph 93.

<sup>793</sup> Transcript, Volume 3, page 420 line 19 to page 421 line 1 (Mr. Sullivan).

<sup>794</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 53-54.

<sup>795</sup> Exhibit 22942-X0331, paragraph 91.

<sup>796</sup> Exhibit 22942-X0560, CGWG argument, paragraph 59.

<sup>797</sup> Exhibit 22942-X0329, paragraphs 69-70.

<sup>798</sup> Exhibit 22942-X0329, paragraph 71, cited at Exhibit 22942-X0560, CGWG argument, paragraph 55.

<sup>799</sup> Exhibit 22942-X0329, paragraph 80.

treatment of a transmission connected generator who “pays its connection costs and is then able to use the embedded transmission network without paying any of the embedded costs.”<sup>800</sup>

728. Fortis argued that in the case of a direct connect customer, because the load and generation components are usually the same entity, the simplified approach of applying the substation fraction is reasonable. In contrast, Fortis submitted that the use of the substation fraction method to determine the supply-related allocation may pass a disproportionate amount of participant-related costs to a DCG considering the actual transmission local connection costs driven by the DCG.<sup>801</sup>

729. Further, Fortis submitted in its reply argument that the evidence in Proceeding 22542, AltaLink’s 2014 and 2015 deferral accounts reconciliation application, demonstrates that the costs paid by DCG for transmission associated with local interconnection may be driven entirely by costs related to serving load. Given this, the AESO’s use of the substation fraction methodology does not reflect the proper allocation of actual interconnection costs to distribution load (DTS) and generation (STS), and is inconsistent with Section 28(1) of the *Transmission Regulation* that requires that owners of generating units pay local interconnection costs.

730. AltaLink supported the AESO’s assessment in its rebuttal evidence<sup>802</sup> that demonstrated that grid services cannot be replaced by DCG. It submitted that the AESO’s proposed changes to metering and contracting practices will result in fair recognition of the value of the grid services provided to load customers and DCG that neither DCG nor DFOs provide or are required to provide, including:

- load following;
- local backup power when DCG power is not available; and
- voltage and frequency support to load.<sup>803</sup>

731. AltaLink referred to an extract from an Electric Power Research Institute (EPRI) report referenced in the AESO’s rebuttal evidence<sup>804</sup> that discussed the services and benefits of grid connectivity to consumers with DCG, including reliability, start-up power, voltage quality, efficiency, and the facilitation of energy market transactions.<sup>805</sup> In addition, AltaLink submitted that the EPRI report highlights the fact that without grid connection, DCG would have to make significant investments in on-site control, storage, and redundant generation capabilities.<sup>806</sup> Given this, AltaLink submitted that the benefits to DCG of connecting to the grid are substantial.<sup>807</sup>

732. AltaLink explained that under the current ISO tariff most grid services such as reliability, start-up power, voltage quality efficiency, and energy transaction are not explicitly metered or charged. Instead, the only mechanism through which market participants can be charged for services obtained through connection to the grid is by way of a DTS or STS contract. AltaLink submitted that the current net-metering practice and DCG credits (discussed in Section 7.3.7 below) result in material cost shifting and cross subsidization, whereas, the AESO’s adjusted

<sup>800</sup> Exhibit 22942-X0329, paragraph 77, cited at Exhibit 22942-X0560, CGWG argument, paragraph 56.

<sup>801</sup> Exhibit 22942-X206, page 6, cited at Exhibit 22942-X0559, Fortis argument, paragraph 34.

<sup>802</sup> Exhibit 22942-X0447, AESO rebuttal evidence at paragraph 85(f).

<sup>803</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 285-287.

<sup>804</sup> Exhibit 22942-X0448, AESO rebuttal evidence Appendix A.

<sup>805</sup> Exhibit 22942-X0048.

<sup>806</sup> Exhibit 22942-X0448, PDF page 1.

<sup>807</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 288-289.

gross metering practice would ensure that the value of grid services is appropriately charged under tariff design and would also ensure that cross subsidization is reduced.<sup>808</sup>

733. AltaLink added that the ISO tariff recovers the embedded costs of the transmission system via its ISO tariff charges to transmission-connected load market participants, whether they be industrial customers or DFOs. In turn, the DFO recovers the ISO tariff charges by flowing the amounts through to its load customers by way of its own tariff. However, a DCG does nothing to reduce or eliminate these embedded costs.<sup>809</sup>

734. The CGWG again asserted in reply that the components of the DTS charges for the bulk, regional and POD costs under the adjusted metering practice, do not reflect the physical flows of energy caused by DCGs.<sup>810</sup> Specifically, it submitted that generation located behind a DFO physically reduces demand flows from the bulk and regional transmission systems. In addition, in circumstances where the energy produced by a DCG exceeds load on its own feeder, energy flows to adjacent feeders across the bus within the POD go up. Under the AESO's proposed metering practice, totalization at the feeder level has the effect of increasing bulk and regional charges and decreasing the POD charge. As such, the CGWG submitted that the allocation of costs arising from the implementation of the AESO's proposed metering practice is in contradiction to the changes in physical energy flows.<sup>811</sup>

735. In response to the suggestions of the AESO and AltaLink that DCGs should be required to pay for benefits they receive from the transmission system, the CGWG submitted that any benefit DCGs receive from the transmission system are also received by transmission connected generators. Therefore, DCGs should pay the same as transmission connected generators to ensure equal treatment and that the allocation of costs to DCGs through the substation fraction is not equal treatment. The CGWG argued that transmission connected generators are only required to pay connection costs, but are not required to pay:

- any embedded costs of past system upgrades;
- any bulk or regional costs; or
- any costs arising from transmission system upgrades after they have connected.

736. Furthermore, the unequal treatment that arises from the fact that the substation fraction method allocates embedded costs to DCGs continues years after the connection.<sup>812</sup>

737. The AESO replied that the CGWG failed to recognize that the cost causation principle requires costs to reflect not only costs caused by the party, but also the benefits obtained as a result of the costs being incurred.<sup>813</sup> By narrowly focusing on whether a DCG directly causes the need for a reliability upgrade,<sup>814</sup> the CGWG fails to take into account the benefits and support that DCG requires from the transmission system to participate in the energy and ancillary services markets. The AESO again submitted that such benefits include the support provided by

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<sup>808</sup> Exhibit 22942-X0048.

<sup>809</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, paragraph 280, PDF page 76.

<sup>810</sup> Exhibit 22942-X0409, CGWG-AUC-2019JAN28-013.

<sup>811</sup> Exhibit 22942-X0574, CGWG reply argument, paragraph 11.

<sup>812</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 25-26.

<sup>813</sup> Exhibit 22942-X0558, AESO argument, paragraph 94, PDF page 37.

<sup>814</sup> Exhibit 22942-X0558, CGWG argument, paragraph 59, PDF page 18.

reliability upgrades completed at the request of DFOs that make system access service decisions on behalf of their end-use customers.<sup>815</sup>

738. The AESO submitted that the CGWG misconstrues the substation fraction issue when it claims that the flow through of supply-related costs amounts to a charge for embedded transmission system costs. The AESO explained that only that portion of connection project costs that have been classified by the AESO as participant-related, and that arise in response to a SASR, are allocated according to the substation fraction formula. Accordingly, costs deemed by the AESO to be “supply-related” costs in accordance with the ISO tariff are a subset of participant-related connection project costs and, as such, are costs related to transmission facilities that would not exist but for the market participant’s request for system access service. Given this, the AESO considered it appropriate that such costs be allocated to STS through the substation fraction.<sup>816</sup>

739. In response to Fortis’s position, the AESO explained that the use of the substation fraction is consistent with the principle of cost causation, even when applied to a DFO with a DCG. From a transmission perspective, the AESO submitted that the substation fraction formula appropriately apportions costs among different services that are provided to a market participant (such as a dual-use customer or a DFO) that receives system access service at a substation that serves as both a point of delivery and a point of supply.

### Commission findings

740. The Commission agrees with the submission of the AESO that the principle of cost causation requires an evaluation of both the costs caused by a party and the benefits accruing to that party. As stated by the Commission in Decision 2008-111:

The Commission considers that the principle of cost causation has long been a relevant factor in the establishment of just and reasonable and not unjustly discriminatory utility rates. Essentially the parties who receive the benefits of utility service should bear the reasonable and prudent costs of incurring that service.<sup>817</sup>

741. The Commission is persuaded that there are significant benefits accruing to DCG that are provided from the transmission system. Specifically, considering the ERPI report filed by the AESO in conjunction with its rebuttal evidence, the Commission understands that both DCG and transmission connected generators benefit from the services that the transmission system provides including system reliability, the availability of start-up power, voltage quality, efficiency and the facilitation of energy market transactions.

742. The substation fraction formula is a long-established mechanism used by the AESO to allocate the costs of local interconnection facilities that may have joint use.<sup>818</sup> Further, while the Commission considers that use of a ratio of the respective STS and DTS contract capacities as a percentage of the combined DTS and STS contract capacities of customers using the local interconnection facilities is a relatively simple mechanism, it is not unreasonable in the absence of any other information. The Commission notes that no parties in the current proceeding have

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<sup>815</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 85.

<sup>816</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 91.

<sup>817</sup> Decision 2008-111, PDF page 14.

<sup>818</sup> Exhibit 22942-X0017.01, PDF page 10.

provided any evidence suggesting that a mechanism other than the substation fraction formula would be an improvement for this purpose.

743. The Commission is not persuaded by Fortis's argument that the AESO's substation fraction is inconsistent with section 28 of the *Transmission Regulation* because costs paid by DCG may be driven entirely by costs related to serving load. Section 28 of the *Transmission Regulation* authorizes the AESO to define local interconnection costs in its tariff and states:

28(1) The ISO must include in the ISO tariff

- (a) local interconnection costs, as defined by the ISO, payable by an owner of a generating unit for connecting to the transmission system,
- (b) the terms and conditions, and
- (c) provisions for the recovery of local interconnection costs from owners of generating units.

744. The Commission further considers that a DFO substation that connects both load and generation serves both load and generation, irrespective of whether the initial impetus behind the DFO's decision to make a SASR was to serve incremental load. Similarly, where a DFO has connected both load and generation to one of its substations, the DFO is responsible to ensure that requirements of both are reflected in the transmission connection facilities that it requests. Where a SASR is received from a DFO, the market participant is not the owner of a generating unit, and the request does not involve the connection of a generating unit directly to the transmission system. Consequently, the Commission agrees with the AESO's interpretation that costs that have been deemed to be supply-related costs in relation to system access service provided to a DFO are properly considered not as "local interconnection costs", but as "costs of the transmission system" that must be wholly charged to the DFO in accordance with Section 47(a) of the *Transmission Regulation*.

745. The proponents of DCG argue that in paying for their local interconnection costs, transmission connected generators pay only the incremental costs associated with the connection of their generation facility. Conversely, the proponents of DCG suggest that the application of the substation fraction to already constructed local connection facilities brought into service through a SASR made by a DFO results in DCG proponents not only paying their incremental costs but also a portion of the "embedded" costs of already constructed local connection facilities. They conclude that this practice is discriminatory.

746. The Commission notes that it is also a long-standing feature of ISO tariffs that market participants that have been required to pay for the participant-related costs of local connection facilities are eligible to receive refunds over the remaining term of their system access contracts when other customers come along and use the local connection facilities. In instances where local connection facilities have been constructed or augmented by a DTS-related system access request, the refund of the contribution to the DTS market participant making the initial system access request will reflect the principle that STS customers do not access the benefit of investment allowances to offset participant costs, and the principle that the mix of DTS and STS contribution policies will be determined through the substation fraction formula.

747. However, a transmission connected generator is typically required to pay, in full and in advance, for the local interconnection facilities it requires to access the AIES and participate in the energy market. A transmission connected generator rarely, if ever, receives a refund of any

portion of its contribution towards such facilities. This is in contrast to a DCG who connects to a DFO substation through distribution voltage feeders who will never be required to pay the full cost of local interconnection facilities that it requires to access the transmission system. Instead, a DCG proponent will only be required to pay an amount determined after consideration of both the STS portion of the substation fraction formula and the remaining term of the DFO's initial DTS contract.

748. Given the above, the Commission disagrees with the suggestion of DCG proponents in this proceeding that transmission connected generators have an advantage arising from the ability to pay only their incremental costs. The Commission understands that even after the revised substation fraction formula and other aspects of the ISO tariff contribution policy is brought into effect through the application of the adjusted metering practice, DCG proponents will generally pay less than transmission connected generators for the benefits of accessing the AIES.

749. Given this, the Commission considers that it is reasonable that the DFO that has both generation and load will, on a go-forward basis (i.e., only go-forward due to grandfathering) be provided a signal through a re-calculation of contribution amounts reflecting the application of the substation fraction.

750. As further discussed in Section 7.3.10, the Commission considers that the manner and quantum of the costs that the DFO flows through to the DCG's connected to specific DFO substations is a matter best addressed in the DFOs tariff and may reflect considerations such as the AESO's proposal to grandfather the application of the adjusted metering practice to substation fraction determination for DCGs that have received a permit and licence prior to the effective date of this tariff, and funding for AESO contribution amounts that the DFO has obtained under the performance-based regulation regime in effect for distribution utilities.

### 7.3.6 Benefits of offsetting load

751. The CGWG referred to the opening statement of its witness, Mr. Hildebrand, that the Government of Alberta implemented its policy to encourage DCG around 1998. Mr. Hildebrand stated that the government was fully aware that electricity could flow from DCG to DFO load customers within a POD, from one feeder to another. As a result, the policy direction of the government was that "any tariff cost savings at a POD resulting from the presence of the DCG would be paid to the DCG for the value delivered, rather than the tariff reduction accruing to the DFO."<sup>819</sup>

752. The AESO responded to the position taken by certain parties in their evidence submissions that DCG offsets load in its argument. In particular, the AESO noted that the evidence of each of Ms. Runge, Mr. Peters and Mr. Whiteside collectively asserts that:

- DCG "offsets" load and, therefore, should not pay transmission costs that would otherwise be allocated to the offset load;
- the transmission system benefits from the asserted offset; and
- the benefit arising from the offset load should be paid to DCG through DCG credits.<sup>820</sup>

<sup>819</sup> Exhibit 22942-X0504, Hildebrand Opening Statement, page 1., cited at Exhibit 22942-X0560, CGWG argument, paragraph 36.

<sup>820</sup> Exhibit 22942-X0329, paragraphs 27-28 and 30, PDF page 8; Exhibit 22942-X0331, paragraph 2(b), PDF pages 3-4; Exhibit 22942-X0331, paragraph 30, PDF page 13; Exhibit 22942-X0334, A10, PDF page 8., cited at Exhibit 22942-X0558, AESO argument, paragraph 64.

753. The AESO submitted that Fortis similarly suggested that the distribution-connected Bull Creek Project displaces DTS load.<sup>821</sup>

754. The AESO argued that, contrary to these assertions, DCG, like transmission connected generation, does not supply a specific load. Instead, the AESO submitted that DCG flows energy into the transmission system to serve load in accordance with the applicable energy market rules.<sup>822</sup>

755. AltaLink submitted in its argument that it is important to recognize that the rationale for net metering of distribution connected generation that was originally set in Decision 2000-1 is not consistent with the drivers of DCG today.<sup>823</sup> In this regard, AltaLink referred to the AESO's response to AESO-AUC-2018NOV01-021, in which the AESO explained that Decision 2000-1 was issued 18 years ago and that many legislative and structure changes have occurred since then. Most importantly, however, AltaLink submitted that the circumstance that has changed and that warrants the AESO's proposed adjusted metering practice is the large influx of DCG projects.<sup>824</sup>

756. In its argument, Fortis submitted that the changes set out in subsection 7.3.2 of the AESO's amended application<sup>825</sup> will partially reverse the findings with respect to the move from gross to net billing approved in Decision 2000-1.<sup>826</sup> However, the AESO does not address the fact that a similar rationale to that used to justify its current proposals was made by the AESO's predecessor to gain approval for the initial move from gross to net billing.<sup>827</sup> In this regard, Fortis noted that:<sup>828</sup>

- In the proceeding leading to Decision 2000-1, the AESO's predecessor proposed that "pricing of transmission for energy transfers and dynamic interchanges with the interconnected transmission system be done on a net basis."
- The AESO's predecessor argued in that proceeding that "net pricing was consistent with cost causation" and that "the current tariff treatment provided an unfair competitive advantage for industrial system co-generation operators over distribution-attached generators."
- The Commission's predecessor ultimately agreed that "the current tariff treatment provides an unfair competitive advantage for industrial system cogeneration operators over distribution attached generators" and concluded "that net pricing is non-intrusive and administratively simpler."<sup>829</sup>

757. The CGWG submitted that the Peters Energy evidence demonstrates that DCG locates where there is existing infrastructure in order to minimize connection costs, and where unserved

<sup>821</sup> Exhibit 22942-X0529, Response to Fortis Undertaking #5, PDF 113, cited at Exhibit 22942-X0558, AESO argument, paragraph 64.

<sup>822</sup> Exhibit 22942-X0558, AESO argument, paragraph 64.

<sup>823</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 302.

<sup>824</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 305.

<sup>825</sup> Exhibit 22942-X0163, Amended application, pages 55-57.

<sup>826</sup> Exhibit 22942-X0559, Fortis argument, paragraph 41.

<sup>827</sup> Exhibit 22942-X0206, pages 2-3, cited at Exhibit 22942-X0559, Fortis argument, paragraph 41.

<sup>828</sup> Exhibit 22942-X0559, Fortis argument, paragraph 40.

<sup>829</sup> Decision 2000-1: ESBI Alberta Ltd. 1999/2000 General Rate Application – Phase I and Phase II, Section 14.4 Gross to Net Billing, February 2, 2000.



load exists, in order to maximize the ability to earn DCG credits.<sup>830</sup> The CGWG submitted that these incentives ultimately lead to locational diversity and reduced energy flow to distribution substations.<sup>831</sup> It claimed that these incentives are significant in light of the testimony provided by Mr. Sharma on behalf of the AESO in the DCG Inquiry (Proceeding 22534) that all customers will eventually benefit from the reduced need for transmission facilities.<sup>832</sup>

758. The DGWG submitted that although the AESO expressed concern that assets as large as 80MW that have traditionally been transmission customers are moving to distribution is a sign of tariff shopping,<sup>833</sup> the AESO could not determine whether any of the larger projects that the AESO had referenced as examples of large customers moving to DFOs were dispatchable generation projects.<sup>834</sup> The DGWG submitted that because dispatchable DCG can be relied upon to offset load in the hours that drive the need for transmission expansion in the long term, the distinction between dispatchable generation and non-dispatchable generation is important. The DGWG submitted that dispatchable DCG is a more reliable source of load reduction than demand responsive load.<sup>835</sup>

759. In its reply, the CGWG explained that when DCG is absent, all energy needed to serve a load flows across the bulk and regional systems and through the POD transformer. However, when DCG is present on a given POD feeder, energy supplied by that DCG will be consumed:

- first on the feeder (detectable via reduced flows from the POD bus to the feeder and reduced flows across the POD transformer);
- second on adjacent feeders (detectable via flow from the DCG feeder to the bus, flow from the bus to adjacent feeders, and further reduced flows across the POD transformer); and
- and finally excess energy will be exported to the regional system (detectable via "reverse" flows across the POD transformer).<sup>836</sup>

760. The CGWG further submitted that if the DCG produces the same amount of power as consumed on the POD, there will be no flow in either direction across the POD transformer because the generation precisely offsets the load. Accordingly, given its submission that DCG offsets load, the CGWG considered that rate design principles such as cost causation support the continuation of DCG credits.<sup>837</sup>

761. In its reply, AltaLink submitted no evidence has been presented to support claims that future transmission expansion will actually be avoided as a result of any DCG development.<sup>838</sup> In the absence of evidence, it is important to bear in mind that the AESO makes up for unfavorable

<sup>830</sup> Exhibit 22942-X0558, CGWG argument, paragraph 9.

<sup>831</sup> Exhibit 22942-X0558, CGWG argument, paragraph 9, citing Exhibit 22942-X0410, CCA-CCWG-2019JAN28-003 (Locational Signals).

<sup>832</sup> Exhibit 22942-X0558, CGWG argument, paragraph 9, citing Proceeding 22534, Transcript, Volume 5, page 560 line 12 to page 561 line 10, as cited in Exhibit 22942-X0447, page 25.

<sup>833</sup> Exhibit 22942-X0562, DGWG argument, paragraph 25.

<sup>834</sup> Exhibit 22942-X0562, DGWG argument, paragraph 26.

<sup>835</sup> Exhibit 22942-X0562, DGWG argument, paragraph 27.

<sup>836</sup> See discussion in Exhibit 22942-X0331, paragraphs 47-56, cited at Exhibit 22942-X0574, CGWG reply argument, paragraph 22.

<sup>837</sup> Exhibit 22942-X0329, paragraph 13, cited at Exhibit 22942-X0574, CGWG reply argument, paragraph 22.

<sup>838</sup> Exhibit 22942-X0257, PDF page 39, AESO-AUC-2018NOV01-021, cited at Exhibit 22942-X0575, AltaLink reply argument, paragraph 92.

revenue variances through riders or increases to DTS rates. In this regard, AltaLink noted that if the AESO is required to make up for revenue shortfalls due to an erosion of billing determinants caused by load customers, this difference is collected from load customers, not from DCGs.<sup>839</sup>

762. In reply, the AESO submitted that in both evidence<sup>840</sup> and argument,<sup>841</sup> the CGWG misconstrued testimony given by AESO witness Mr. Sharma in Proceeding 22534. The AESO noted that in its rebuttal evidence,<sup>842</sup> it had explained that Mr. Sharma did not testify in Proceeding 22534 that DCG will generally reduce future transmission costs.<sup>843</sup>

### **Commission findings**

763. The Commission is not persuaded by the evidence that there is a one-to-one offset between energy dispatched by DCG and load served by the same distribution substation. This finding primarily reflects two observations.

764. First, the Commission notes the evidence discussed in this proceeding indicates that the capacity of some DFO substations may be well in excess of requirements for load growth for the foreseeable future,<sup>844</sup> which is contrary to the expectation that DCG would cause DFO's to limit the transmission capacity they would request in SASRs.

765. Second, much of the recent interest in DCG is in respect of renewable forms of generation for which the timing of generation peaks may not correspond to the timing of load peaks that drive transmission expansions.<sup>845</sup>

766. The Commission recognizes that the belief that distribution-connected generation provides an offset to load growth and, thereby, avoids transmission expansion costs that would otherwise be required was central to the historical decision of the Commission's predecessor to find that credits for distribution connected generation should be provided by DFOs. However, the Commission considers that the decision on whether or not there should be DFO funded credits for distribution-connected generation is a separate matter. This is discussed in Section 7.3.7 below.

#### **7.3.7 Distribution connected generation credits**

767. DCG credits, sometimes referred to as transmission credits, were examined in this proceeding, and were explained in the DCG Inquiry as follows:

271. ATCO Electric, ENMAX and FortisAlberta tariffs all include a provision that provides a transmission tariff-based credit to large-scale DCG providers.....

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<sup>839</sup> Exhibit 22942-X0575, AltaLink reply argument, paragraph 91.

<sup>840</sup> Exhibit 22942-X0331, CGWG evidence, paragraphs 28-29, PDF 12.

<sup>841</sup> Exhibit 22942-X0560, CGWG argument, paragraph 9, PDF 6.

<sup>842</sup> Exhibit 22942-X0447, AESO rebuttal Evidence, at para. 85(i), PDF pages 25-26.

<sup>843</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 57.

<sup>844</sup> The Commission notes, for example, that the evidence of AltaLink (Ex. ) has suggested that the AESO contribution amounts of Fortis are excessive, and attributes this to considerations such as the absence of AESO oversight and an incentive on behalf of Fortis to build rate base.

<sup>845</sup> See for example the argument submitted by the DGWG at paragraph 24 of its argument submission (Exhibit 22942-X0562, paragraph 24).

272. FortisAlberta's credit is referred to as Option M, ATCO Electric's credit is referred to as rate D32 and ENMAX's credit is known as rate D600. Neither EPCOR nor the REAs currently offer these credits.

273. FortisAlberta explained that its Option M was originally intended to incent gas flare generation as a means of offsetting the environmental impact of flaring activity. These Option M credits have evolved and now serve as a subsidy paid by load customers to incent DCG customers to deliver electrical energy to the distribution system as a means of reducing transmission charges.

274. The credits are calculated based on the electrical energy delivered by the distribution connected generator to the distribution system, and are the difference between the AESO system access service charges to the distribution wire owner (with the generator in operation) and the charges that would have been incurred if the generator had not been in operation. The amounts are calculated manually for each DCG using actual hourly metering data.[footnote removed]

768. As set out in the AESO's amended application, the AESO considered "that there should be no economic advantage that can be achieved by a generator that connects to the transmission system versus the electric distribution system, or vice versa. For example, a DCG should not receive distribution derived transmission credits ..."<sup>846</sup>

769. In argument, the CGWG noted that in the AESO's response to AESO-AE-2018NOV01-014(b),<sup>847</sup> the AESO indicated that to ensure FEOC treatment of both distribution and transmission connected generation, the AESO considers that subsidies at distribution levels must be eliminated by DFOs.<sup>848</sup> However, the CGWG submitted that the AESO's response did not adequately explain why the ISO tariff is the appropriate forum in which to address DCG credits. The CGWG submitted that the DFO tariff proceeding is the appropriate place to address DCG credits because that is where the credits reside.<sup>849</sup>

770. In its argument, ENMAX expressed the view that issues arising from the AESO's alternative metering proposal requiring alignment with DFO tariffs were not fully dealt with in the current proceeding and should be addressed in the Commission's Distribution System Inquiry. Alternatively, ENMAX submitted that these issues should be examined as part of the AESO's 2020 tariff proceeding.<sup>850</sup>

771. The DGWG submitted that the AESO's evidence that the original change to net billing adopted in Decision 2000-1 was predicated on a lower level of load from "stable" generation. The DGWG noted that most DCGs today are predominantly intermittent generation sources such as solar or wind and, thus, would not provide a stable level of load reduction. The DGWG submitted that although DCG from intermittent sources cannot be relied on for transmission system planning purposes,<sup>851</sup> dispatchable sources of DCG that are sized, sited and operated to

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<sup>846</sup> Exhibit 22942-X0163, Amended application, paragraph 213a.

<sup>847</sup> AESO-AE-2018NOV01-014(b), Exhibit 22942-X0253, PDF pages 21-22, cited at Exhibit 22942-X0560, CGWG argument, paragraph 32.

<sup>848</sup> Exhibit 22942-X0560, CGWG argument, paragraph 32.

<sup>849</sup> Exhibit 22942-X0560, CGWG argument, paragraph 33.

<sup>850</sup> Exhibit 22942-X0547, ENMAX argument paragraph 12.

<sup>851</sup> Exhibit 22942-X0562, paragraph 24.

optimize the attainment of distributed generation credits aligns with the underlying premise for DCG credits.<sup>852</sup>

772. Fortis submitted that any consideration of how Option M may be applied in the future depends on Commission determinations in respect of gross versus net metering practices.<sup>853</sup> In this regard, Fortis noted that in response to an undertaking request, Fortis explained that it had paid approximately \$1.5 million in Option M credits to BluEarth for its Bull Creek Project for the 12 production months of 2018, but that the total value of Option M credits paid to BluEarth would have been reduced by approximately 58 per cent had the AESO's proposed ID 2018-019T been in place during that year.<sup>854</sup>

773. Fortis explained that it continues to offer Option M credits because it has not been directed to do otherwise. Fortis stated that the transmission costs that it flows through to its customers are one or two percent higher as a result of the Option M credits but that it is uncertain as to whether this state of affairs is sustainable.<sup>855</sup> If it is determined that Option M should be altered, Fortis submitted that this should be done through revisions to the distribution tariff, and not through a change in metering practice "as a stop-gap measure."<sup>856</sup>

774. In its argument, AltaLink submitted that the Commission should consider the elimination of DCG credits offered by DFOs in future DFO rate design hearings.<sup>857</sup> Notwithstanding this position, AltaLink presented its views on the continuation of these credits in this proceeding.

775. It noted that the AESO's position on DCG credits is that DCG does not generally defer or reduce future transmission costs, that DCG cannot be relied on for planning purposes,<sup>858</sup> and that continued penetration of DCG will erode DTS billing determinants, resulting in higher DTS rates and cross-subsidization between market participants.<sup>859</sup>

776. AltaLink submitted that DCG proponents have consistently asserted that DCG reduces the transmission charges paid by a DFO to the AESO,<sup>860</sup> and that those DFOs who do not provide a transmission credit are unfairly retaining the value of these benefits.<sup>861</sup> However, such views fail to recognize the true impact of DCG on the distribution and transmission systems. In this regard, AltaLink referred to the following Commission findings in the Commission's Final Report to the Alberta Electric Distribution System-Connected Generation Inquiry (DCG Inquiry):<sup>862</sup>

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<sup>852</sup> Exhibit 22942-X0562, paragraphs 29-30.

<sup>853</sup> Transcript, Volume 7, page 1159, lines 19-23.

<sup>854</sup> Exhibit 22942-X0541, Undertaking IR Response to FAI-AUC-2019APR12-005(a)(ii)., cited at Exhibit 22942-X0559, Fortis argument, paragraph 48.

<sup>855</sup> Transcript, Volume 7, page 1158, lines 4-18., cited at Exhibit 22942-X0559, Fortis argument, paragraph 47.

<sup>856</sup> Exhibit 22942-X0559, Fortis argument, paragraph 47.

<sup>857</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 304.

<sup>858</sup> Exhibit 22942-X0447, AESO rebuttal evidence at paragraph 85(h); also Exhibit 22942-X0257, PDF page 45, AESO-AUC2018NOV01-021.

<sup>859</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 290.

<sup>860</sup> See for example Exhibit 22942-X0329, CanSIA evidence, Appendix A at paragraph 15, PDF page 6; Exhibit 22942-X0331, CanSIA evidence, Appendix B, paragraph 30, PDF pages 12-13.

<sup>861</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, paragraph 280, PDF page 76.

<sup>862</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, PDF page 74.

- The views of DCG proponents on transmission tariff-based credits were completely at odds, and DCG proponents exhibited a “large gap” in the understanding of both the drivers of and allocation of transmission and distribution system investments.<sup>863</sup>
- Because the AESO does not provide a credit to DFOs for reduced transmission wires costs due to DCG, the DFOs must recover the cost of their credits from all of their customers. This amounted to a cross-subsidy from non-DCG customers to DCG customers.<sup>864</sup>

777. AltaLink also noted that during the oral hearing in the DCG Inquiry,<sup>865</sup> Fortis explained that the original intention of Fortis’s Option M credit was to incent a single load customer to use gas flare generation to offset the environmental impact of gas flaring. However, the AESO explained in its response to AESO-AUC-2018NOV01-021 that certain DFOs have allowed the credits to evolve from their original purpose without considering changes that have occurred since DCG credits were originally approved.<sup>866</sup>

778. AltaLink further submitted that it is significant that EDTI does not offer DCG credits. EDTI’s explanation for this choice during the DCG Inquiry was as follows:

... the so-called credit, it doesn't reflect an actual reduction in the cost of anything because the DTS tariff reflects the cost of the transmission system, which similar to how I described the distribution system, is based on the facilities that have been installed that are out there. So simply connecting a DCG customer to a transmission system in no way affects the cost of the transmission system. What it may do, though, it just may change how that cost is allocated to different customers.

So if a DCG connects to a particular distribution system and that reduces the amount of electricity that's delivered from the transmission system to that particular distribution system, then that distribution system owner will pay less DTS costs to the AESO. But the AESO will still have the same costs on their side of the equation. So they'll simply do a true-up either through a rate adjustment or through their deferral account system to collect that missing revenue. So it just gets moved around, and there is no reduction in costs. So we don't see why there should -- a credit should be given to a customer that comes onto our system.<sup>867</sup>

779. Based on Fortis’s testimony that Fortis’s flow-through of transmission costs to its customers is in the range of \$800 million to \$900 million and that these costs are one or two per cent higher because Fortis pays out Option M credits to DCGs,<sup>868</sup> AltaLink estimated that Fortis’s expenditures on DCG credits would be in range of \$8 million to \$18 million.<sup>869</sup>

780. In addition, in response to a question from Commission counsel, Fortis indicated that it paid in the order of \$1.5 million in Option M credits to BluEarth for the 12 production months of

<sup>863</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, PDF page 74.

<sup>864</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, PDF page 75.

<sup>865</sup> Transcript, Volume 7, page 1157, line 12 to page 1158, line 3.

<sup>866</sup> Exhibit 22942-X0257, PDF page 42, AESO-AUC-2018NOV01-021, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 303.

<sup>867</sup> Proceeding 22534, Distribution System-Connected Generation Inquiry - Final Report, paragraph 275, PDF pages 75-76, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 294.

<sup>868</sup> Transcript, Volume 7, page 1158, lines 14-17.

<sup>869</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 299.

2018.<sup>870</sup> In response to an IR on an undertaking (FAI-AUC-2019APR12-005), Fortis indicated that, from 2015 to January 2019, the cumulative amount of Option M payments paid to Bull Creek was \$4.0 million.<sup>871</sup> However, AltaLink submitted that Fortis's Option M payouts do not reflect an actual reduction to embedded transmission costs or to Fortis's system access costs because after all of the AESO's true-up processes are complete, Fortis's system access costs are ultimately recovered from its load customers.<sup>872</sup>

781. Responding to ENMAX in reply, the AESO noted that, in spite of filing initial submissions on the adjusted metering practice at an earlier stage of the proceeding,<sup>873</sup> ENMAX chose not to submit evidence on the issue. Given this, the AESO considered ENMAX's suggestion that the adjusted metering practice has not been "fully dealt with" to be an obvious attempt to delay implementation of the AESO's proposal that should be disregarded by the Commission.<sup>874</sup>

782. In response to the CGWG, the AESO acknowledged in this proceeding that the issue of whether distribution tariffs that provide DCG credits should be continued is ultimately a distribution tariff matter.<sup>875</sup> However, it considered that its metering practice and the issue of the need for accurate billing determinants to be an ISO tariff matter. Further, the record concerning these matters has been fully developed in the proceeding.<sup>876</sup>

783. The AESO also clarified that its concern was not the DFO credit provided to generators, as suggested by the CGWG in its argument, but the "out-of-market subsidy that POD-level totalization provides to DCG at the expense of Alberta ratepayers through the erosion of DTS MW."<sup>877</sup>

784. In its reply, Fortis also expressed the view that, based on the AESO's argument, the primary reason, if not the only reason, for the AESO's proposed implementation of ID 2018-019T is the existence of credits that are available to DCG.<sup>878</sup> It noted that the AESO stated:

the AESO reviewed its existing metering practice and has determined that the existing net metering practice and the DCG credits that the net metering practice enables are no longer appropriate and should be discontinued ...<sup>879</sup> [emphasis added by Fortis]

785. Fortis submitted that the AESO's proposed adjusted metering practice is a crude and ineffective method of addressing the AESO's primary concern with credits to DCG.<sup>880</sup> It submitted that as distribution credits reside in the distribution tariffs of the DFOs that offer them,

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<sup>870</sup> Exhibit 22942-X0529, Fortis Undertaking 5 Response, PDF 113.

<sup>871</sup> Exhibit 22942-X0541, PDF page 17.

<sup>872</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 301.

<sup>873</sup> Exhibits 22942-X0161 and 22942-X0204.

<sup>874</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 52.

<sup>875</sup> Exhibits 22942-X0161 and 22942-X0204, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 51.

<sup>876</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 52.

<sup>877</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 61.

<sup>878</sup> Exhibit 22942-X0558, paragraphs 52, 54 55, 68 and 69, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 40.

<sup>879</sup> Exhibit 22942-X0558, paragraph 54, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 40.

<sup>880</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 41(a).

the Commission's deliberations regarding the credits available to DCG should be undertaken in a distribution tariff proceeding.<sup>881</sup>

### Commission findings

786. The Commission accepts the AESO's position that the AESO was motivated primarily by its concern that DCG receives a preferable non-allocation of local interconnection costs that could lead to substantial billing determinant erosion (as discussed in Section 7.3.1). Although the AESO noted that DCG credits provide additional advantages to DCG over transmission connected generation beyond that provided by the avoidance of the allocation of local interconnection costs through the substation fraction, the Commission is satisfied that the elimination of DCG credits was not the AESO's primary motivation for advancing its adjusted metering proposal.

787. The Commission observes that there is evidence on the record of this proceeding on the cross subsidy created by DCG credits and the resulting transfer of transmission costs to load customers without a corresponding reduction in the actual cost of the transmission grid, requiring recovery in the ISO tariff. Nevertheless, the Commission agrees with parties that the continuation of DCG credits is a distribution tariff matter. Further, an examination of the claim by the DGWG that there are significant differences in the characteristics of "dispatchable" and "non-dispatchable" forms of DCG warranting the continuation of DCG credits for certain types of generation should be included in any future examination of the continued availability of DCG credits.

### 7.3.8 Grandfathering proposal

788. In its argument, the AESO provided the following general overview describing how it intended to implement its alternative metering proposal. Specifically, the AESO explained that:

- if approved, its adjusted metering practice would apply with the coming into effect of the 2018 ISO tariff;
- connection projects that are energized or for which a permit and licence has been issued and construction has commenced prior to the effective date of the 2018 ISO tariff would be exempted from the adjusted metering practice;
- the AESO would use existing meters for substations; and
- if a generator is initially exempt and then makes amendments to critical information in a SASR or is required to submit a new SASR, the generator would be subject to the adjusted metering practice on a go-forward basis.<sup>882</sup>

789. The CGWG submitted that the AESO's proposed grandfathering provisions will serve to discriminate against solar generation, and particularly community generation. In its argument, Solar Krafte submitted that, during cross-examination by counsel for the CGWG,<sup>883</sup> Mr. Sullivan, on behalf of the AESO, acknowledged that Alberta DCGs would face "limitless, unpredictable costs" that could potentially dwarf the book value of the DCGs. Solar Kraft submitted that such a situation is "unprecedented and ridiculous" because DCGs would, in most cases, be the only generators paying for transmission upgrades yet at the same time would be precluded from

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<sup>881</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 41.

<sup>882</sup> Exhibit 22942-X0558, AESO argument, paragraph 59.

<sup>883</sup> Transcript, Volume 1, page 173, cited at PDF pages 1-2 of Solar Krafte argument (Exhibit 22942-X0548).

requiring or affecting the upgrades. In practice, Solar Krafte submitted that this will make DCGs requiring an STS contract completely non-viable, with the effect that extremely desirable DCGs will be removed from the generation mix.<sup>884</sup>

790. It submitted that the AESO should examine grandfathering issues, including a full consultation, in the context of the AESO's ISO rule development process because the AESO's grandfathering protections do not apply in many important circumstances. In this regard, the CGWG submitted that the AESO's grandfathering proposals did not appear to benefit:

- generation developers that have not started construction by the completion of this proceeding;
- generation developers that make any adjustment to their output; and
- generation developers who make any adjustments to their originally-planned in-service dates.<sup>885</sup>

791. The DGWG argued that grandfathering creates generational inequity within an existing generation class. It further submitted that the right to be grandfathered is tenuous because market participants do not have a vested right to be exempted from all future changes in AESO requirements or practices.<sup>886</sup> It considered the AESO's proposal to evaluate the eligibility of DCG projects for grandfathered treatment on a case-by-case basis to be ambiguous, and to create management difficulties for DCG entities.<sup>887</sup> In addition, the DGWG submitted that the complexity arising from the need to determine how the grandfathering of ID 2018-019T would be applied at substations with multiple DCGs connected prior to and after ID 2018-019T implementation should not be understated.<sup>888</sup>

792. Fortis submitted in its reply argument that the AESO's position on grandfathering provides additional evidence of the deficiencies of the AESO's proposed adjusted metering practice. Fortis was particularly critical of the AESO's statement in regards to grandfathering that its adjusted metering practice will apply if:

... a new generator to which the adjusted metering practice does not initially apply (i.e., because the generator is initially grandfathered) amends the critical information in its SASR or is required to submit a new SASR, the generator would from that point forward be required to comply with the adjusted metering practice.<sup>889</sup>

793. Fortis claimed that the AESO's implementation was deficient for two reasons. First, the AESO's concern is not with the activities of the DFO at a substation but instead is limited to those cases where there is DCG. Second, Fortis noted it is not the generator who applies to the AESO for the SASR but the DFO. In any event, Fortis noted that a SASR submitted by the DFO may be as a result of the generator's request or for some other reason.

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<sup>884</sup> Exhibit 22942-X0548, Solar Krafte argument, PDF page 2.

<sup>885</sup> Exhibit 22942-X0271, AESO-CanSIA-2018NOV01-001, cited at Exhibit 22942-X0574, CGWG reply argument, paragraph 12.

<sup>886</sup> Exhibit 22942-X0447, AESO rebuttal evidence, PDF page 28, cited at Exhibit 22942-X0562, DGWG argument, paragraph 33.

<sup>887</sup> Exhibit 22942-X0562, DGWG argument, paragraph 35.

<sup>888</sup> Exhibit 22942-X0562, DGWG argument, paragraph 36.

<sup>889</sup> Exhibit 22942-X0558, AESO argument, paragraph 59.



794. Fortis submitted that to the extent that the AESO acknowledges that grandfathering "... represents discrimination among market participants by applying a new requirement unequally,"<sup>890</sup> the AESO should avoid this requirement to grandfather, where possible.<sup>891</sup>

795. AltaLink supported the AESO's proposal related to grandfathering.<sup>892</sup>

### Commission findings

796. As with any change in practice, prior parties will receive different treatment than future entities. Consequently it is reasonable for the AESO to propose a transition period for the implementation of its adjusted metering practice. The Commission finds the AESO's implementation and grandfathering proposal to be a reasonable approach. It allows existing DCG proponents to continue to operate under the regime under which these proponents initially brought forward their generation projects. Further, it is not unjust or unreasonable to treat new DCG proponents who have yet to receive a permit and licence and begin construction in the same way as an existing DCG proponent who is seeking to substantially change its SASR. In both circumstances, the DCG proponent is aware of the costs it would be subject to, prior to proceeding with its project.

#### 7.3.9 Retroactive ratemaking

797. The CGWG submitted in argument that the allocation of costs to DCG through the substation fractioning allows for retroactive ratemaking by allocating the cost of future substation upgrades to existing DCGs. It stated that the evidence revealed that a number of DCG developers were informed by the AESO or by Fortis that they would be subject to costs well after their connection to the AIES had been completed. The CGWG submitted that DCGs should not be responsible for revised costs revealed only after investments decisions have been made, based on costs represented as final. Accordingly, it recommended that the Commission direct the AESO to consult with market participants on methods the AESO can use to "eliminate the issuance of revised costs."<sup>893</sup>

798. ATCO Electric agreed with the recommendations and related rationale provided by the CGWG to continue to maintain an incremental approach to DCG connection costs, with no retroactive allocation of previous substation costs based on fractioning, and no allocation of future substation upgrade costs to existing DCGs.<sup>894</sup>

799. The AESO rejected claims that the substation fractioning formula was discriminatory, that it arbitrarily "reveals" further costs after investment decisions have been made, or that it leads to retroactive ratemaking.<sup>895</sup> The AESO submitted that it would be prudent for the DFO to provide its end-use customers with as much advance notice as possible of reliability upgrades, particularly in circumstances where costs could be deemed as supply-related and the DFO determines that such costs should be flowed through to the DCG.<sup>896</sup>

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<sup>890</sup> Exhibit 22942-X0558, AESO argument, paragraph 60.

<sup>891</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 41(b).

<sup>892</sup> Exhibit 22942-X0575, AltaLink reply argument, paragraph 100.

<sup>893</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 77-78.

<sup>894</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 60.

<sup>895</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 84.

<sup>896</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 86.

800. The AESO added that to the extent the potential allocation of costs of future substation upgrades could be viewed as retroactive ratemaking, then it would be “permissible retroactive ratemaking” because market participants will have knowledge that rates may change.<sup>897</sup> In this regard, the AESO noted that in Decision 790-D02-2015,<sup>898</sup> the Commission examined the circumstances under which retroactive ratemaking can be considered permissible, one of which is the “knowledge exception.”<sup>899</sup> Following its review of the Alberta Court of Appeal’s decision in *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)* 2014 ABCA 28, the Commission concluded that four propositions can be drawn from that decision:

First, as a general rule, it is the knowledge of affected parties that rates may change which renders permissible what would otherwise be impermissible retroactive ratemaking. Second, knowledge that rates may be subject to change can be acquired in more than one way. Third, in some cases, it will be obvious from the very nature (if not nomenclature) of the regulatory proceeding in which rates are being examined, that the outcome of the proceeding may involve retroactive or retrospective changes to past rates.... And fourth, in other situations, it may be less obvious from the name or general nature of the proceeding that rates may change with retroactive or retrospective effect. In those situations, it will be necessary for the regulator to place parties on notice, by its words or actions, that rates may be subject to change....<sup>900</sup>

801. The AESO noted that the “knowledge exception” was accepted by the Commission to arise when parties acquire knowledge that rates may change due to a complaint being filed, or a proceeding otherwise being commenced with a regulatory body.

802. The AESO submitted that its recalculation of supply-related and demand-related costs only occurs in response to a SASR submitted by the DFO, in accordance with the terms explicitly set out in sections 8 and 9 of the current ISO tariff, and with sections 4 and 5 of the proposed 2018 ISO tariff.<sup>901</sup> Accordingly, the AESO submitted that, should the Commission approve sections 4 and 5 of the proposed 2018 ISO tariff in this proceeding, DCG market participants will have or can be taken to have knowledge of the circumstances when the recalculation by the AESO of supply-related and demand-related costs will be carried out. Therefore, such recalculation would not be impermissible retroactive ratemaking.<sup>902</sup>

### Commission findings

803. In *Capital Power Corporation v Alberta Utilities Commission*,<sup>903</sup> the Alberta Court of Appeal upheld the Commission’s recitation of the law on permissible retroactive ratemaking stating

[61] The Commission also invoked the knowledge exception to find it had jurisdiction to grant a retroactive tariff-based remedy.... The Commission’s finding that the

<sup>897</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 87.

<sup>898</sup> Decision 790-D02-2015: Milner Power Inc., Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, ATCO Power Ltd., Complaint regarding the ISO Transmission Loss, Factor Rule and Loss Factor Methodology, Phase 2 Module A, January 20, 2015 (“Module A Decision”).

<sup>899</sup> Module A Decision, paragraphs 153-154, PDF page 46.

<sup>900</sup> Module A Decision, paragraph 196, PDF page 60.

<sup>901</sup> Exhibit 22942-X0014.03, Appendix R, PDF pages 62-74.

<sup>902</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 89.

<sup>903</sup> *Capital Power Corporation v Alberta Utilities Commission*, 2018 ABCA 437.

province's electricity generators had knowledge very early in the piece that the rates were subject to retroactive or retrospective change simply cannot be credibly challenged.

[63] With respect to the applicants' arguments that the Commission's decision violates the rule against retroactive ratemaking, the first point to be made is that the *Electric Utilities Act*, like most public utility statutes, does not expressly prohibit retroactive ratemaking. [...] Following the 2007 amendments and the repeal of section 126, one would be hard-pressed to find an express prohibition in the *Electric Utilities Act* against retroactive ratemaking, ...

[64] The reason that there is no blanket prohibition against retroactive ratemaking is that there are decades of public utility board and judicial decisions variously applying the rule or declining to apply the rule depending on circumstances.... Whether that is a fair characterization of the jurisprudence, no court or public utilities board will ever be able to define precisely the circumstances in which retroactive ratemaking is permissible. Nor is it desirable that they should do so. And, presumably, it has been deemed even less desirable to enact a blanket prohibition.

[65] The rule against retroactive ratemaking is applied when considerations of fairness, reliance, rate stability and certainty are engaged and given more weight than countervailing considerations. By way of examples, the rule is often not applied in the context of regulatory changes to accounting methodology, when obvious mistakes have been made in rate orders, when utilities experience extraordinary losses or gains or other exceptional (novel and complex) circumstances. It is often not applied when rate orders are quashed or reversed following judicial review. And it is often not applied when retroactive relief is granted by the utility regulator following a lengthy tariff proceeding or in cases of interim rates subject to change or in cases of deferral accounts employed to deal with differences between forecast and actual costs and revenues. There are other circumstances as well in which the rule is not applied. The list is not closed.

[66] The point being made is that the Commission's application of the rule against retroactive ratemaking is not so much a question of law but a question of whether or not a strict application of the rule in the circumstances of the case achieves sound utility regulation....

804. In the present circumstance, as noted in Section 7.3.8 above (grandfathering), it is not unfair for DCG proponents to be subject to the changes resulting from the application of the AESO's adjusted metering practice and substation fractioning on future DFO substation projects. Further, parties have had knowledge of this proposed change for many months. As such, the Commission considers that the fact that DCG proponents may be subject to costs caused by the application of the AESO's adjusted metering practice and substation fractioning to future DFO substation projects does not constitute impermissible retroactive ratemaking.

### **7.3.10 DFO discretion to flow-through substation fraction amounts**

805. The CGWG witness, Ms. Runge, provided a letter dated September 2018 prepared by Fortis to illustrate the effect of the application of the AESO's adjusted metering practice and substation fractioning to DCG proponents. In this letter, Fortis indicated that the construction contribution decision for the distribution POD used to connect BluEarth's 29.5 MW project had been revised, with the effect that approximately \$11 million in additional costs would be

required from BluEarth as a result of two reliability upgrades.<sup>904</sup> The CGWG noted that this additional allocation of costs represents approximately 14 per cent of the Bull Creek Project expenditures of approximately \$80 million.<sup>905</sup>

806. The CGWG added that the September 2018 letter to BluEarth was received almost three years after the Bull Creek Project was completed, and discusses substation changes to occur in 2020.<sup>906</sup> The CGWG took note of the testimony of Ms. Runge during the oral hearing that the AESO's policy essentially requires DCGs to write a number of "blank cheques" when they connect that can be cashed any time in the next 20 years because the DCG developer cannot control whether the substation is going to be upgraded, nor the cost of upgrades. Ms. Runge noted that the risk of this unknown future liability is likely sufficient to halt many DGC projects.<sup>907</sup>

807. In consideration of the risk of being liable for future substation upgrade costs, the CGWG also referenced Proceeding 23339 in which the Central East Transmission Development (CETD) Project, an AESO system project, which included a Provost to Hayter transmission line, was eventually constructed by Fortis as a reliability project.<sup>908</sup> The CGWG noted that Fortis moved ahead with the Provost Reliability Upgrade Project, with the consequence that BluEarth was assessed \$2.1 million.<sup>909</sup> Given this outcome, it is obvious that DCG developers will prefer that the AESO initiate reliability upgrade projects because, in that case, the DCG developers will not be responsible for any costs.<sup>910</sup> The CGWG submitted that the idea that costs can be allocated to a DCG when Fortis initiates a reliability project but no allocation occurs when the AESO initiates a similar system project is illogical, since both the CETD Project and the Provost Reliability Project were implemented to fulfill the same underlying reliability need.<sup>911</sup>

808. Fortis similarly expressed concerns in argument regarding the provisions in sections 8 and 9 of the ISO tariff that permit the AESO to reassess construction contribution decisions with respect to a project or substation. Fortis submitted that a possible reassessment of CCDs creates a mitigatable risk for DCG customers.<sup>912</sup> Fortis referenced examples presented in the evidence of Ms. Runge respecting BluEarth's receipt of a CCD for its Bull Creek Project that allocated \$9 million in costs to it resulting from a reliability system upgrade, and in the evidence of Solar Krafte, respecting the re-assessment of the substation fraction at the Spring Coulee 385S substation project (AESO project 1338) and subsequent flow-through of this cost by Fortis increasing Solar Krafte's cost for a DCG project by \$4,889,545.<sup>913</sup>

<sup>904</sup> Transcript, Volume 4, page 752 line 20 to page 753 line 5 (Ms. Runge).

<sup>905</sup> \$11 million is the addition of \$9 million at Transcript, Volume 4, page 753 lines 8-11 (Ms. Runge) and \$2.1 million at Transcript, Volume 4, page 755 line 22 (Ms. Runge).

<sup>906</sup> Exhibit 22942-X0560, CGWG argument, paragraph 73.

<sup>907</sup> Transcript, Volume 4, page 754 lines 2-14 (Ms. Runge) and Exhibit 22942-X0519, CGWG Transcript Corrections., cited at Exhibit 22942-X0560, CGWG argument, paragraph 74.

<sup>908</sup> Transcript, Volume 7, page 1138 lines 2-16 (Mr. Eck). and Transcript, Volume 7, page 1143 lines 4-10 (Mr. Eck).

<sup>909</sup> Transcript, Volume 4, page 755 line 22 (Ms. Runge).

<sup>910</sup> Transcript, Volume 7, page 1146 line 22 – page 1147, line 1 (Mr. Eck).

<sup>911</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 63-65.

<sup>912</sup> Exhibit 22942-X206, page 6, cited at Exhibit 22942-X0559, Fortis argument, paragraph 35.

<sup>913</sup> Exhibit 22942-X0319, page 1, cited at Exhibit 22942-X0559, Fortis argument, paragraph 36.

809. The AESO submitted in its argument that because the DFO holds the Rate STS contract, it is responsible for determining the allocation of ISO tariff charges to DCGs and other DFO end-use customers in accordance with its applicable distribution tariff.<sup>914</sup>

810. Contrary to the position advanced by the AESO, Fortis argued that it is required to flow through to the DCG customer any amount deemed to be supply-related by the AESO through its substation fractioning.<sup>915</sup> Fortis submitted that it must do so because this would be consistent with Section 28 of the *Transmission Regulation* and Article 12.6.1 of Fortis's Customer Terms and Conditions of Electric Distribution Service.

811. Further, Fortis submitted that because it is required to flow through these charges to its DCGs, it can play no role in mitigating the continual risk that DCGs may be exposed to additional transmission interconnection charges years after the interconnection process.<sup>916</sup>

812. The CGWG claimed in its argument that the AESO's position with respect to the flow-through of costs arising from customer contribution decision changes, as explained by Mr. Sullivan on behalf of the AESO, is as follows:

- AESO construction contribution decisions provided to DFOs deem costs to be either supply-related or demand-related;<sup>917</sup>
- the AESO does not impose any requirement on the DFO to flow through costs to end-use customers following the deeming of costs in the construction contribution decision; and<sup>918</sup>
- the AESO does not believe it has the jurisdiction to pass along costs to end-use customers.<sup>919</sup>

813. The CGWG also asserted that Mr. Sullivan testified that the AESO:

- considers that the DFO should be flowing down costs to the DCG;<sup>920</sup>
- would recommend that the DFO flow down costs to the DCG;<sup>921</sup> and
- would be concerned if the DFO were not flowing down the costs to the DCG.<sup>922</sup>

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<sup>914</sup> Exhibit 22942-X0558, AESO argument, paragraph 90.

<sup>915</sup> Transcript, Volume 7, pages 1130, lines 14-22.

<sup>916</sup> Exhibit 22942-X0559, Fortis argument, paragraph 38.

<sup>917</sup> Transcript, Volume 1, page 170 lines 1-2 (Mr. Sullivan). Also see Transcript, Volume 1, page 166 lines 21-22; Transcript, Volume 1, page 167 lines 12-13; Transcript, Volume 1, page 168 lines 9-14; Transcript, Volume 1, page 168 lines 19-22; Transcript, Volume 1, page 169 lines 8-9 (Mr. Sullivan); Transcript, Volume 1, page 170 lines 1-35 (Mr. Sullivan).

<sup>918</sup> Transcript, Volume 1, page 167 lines 10-12 (Mr. Sullivan). Also see Transcript, Volume 1, page 166 lines 19-20 (Mr. Sullivan); Transcript, Volume 1, page 169 lines 9-11 (Mr. Sullivan).

<sup>919</sup> Transcript, Volume 1, page 171 lines 4-6 (Mr. Sullivan); Transcript, Volume 3, page 622 lines 5-12 (Mr. Sullivan).

<sup>920</sup> Transcript, Volume 1, page 168 lines 9-14 (Mr. Sullivan); Transcript, Volume 3, page 623 lines 16-17 (Mr. Sullivan).

<sup>921</sup> Transcript, Volume 1, page 168 lines 19-22 (Mr. Sullivan).

<sup>922</sup> Transcript, Volume 1, page 170 line 25 – page 171 line 1 (Mr. Sullivan); Transcript, Volume 3, page 623 lines 23 (Mr. Sullivan).

814. The CGWG further noted Fortis's position that its terms and conditions provide for the flow-through to DCG of any amounts deemed to be supply-related and that Fortis considers that it has no discretion to not flow through costs to DCGs.<sup>923</sup>

815. The CGWG submitted that the lack of clarity with respect to the DFO's obligation to flow through cost allocations determined in construction contribution decisions is problematic. Accordingly, it requested that the Commission confirm whether the DFO has discretion to flow through costs in a manner different than set out in an AESO construction contribution decision. Further, in the event that the Commission determines that a DFO is required to flow through construction contribution decision costs, it would be helpful if the Commission could explain in its decision whether its determination on this matter is based on language within DFO terms and conditions or on the basis of the *Transmission Regulation*.<sup>924</sup>

816. ATCO argued that it considers the AESO's adjusted metering proposal to be inconsistent with other applicable sections of the AESO's terms and conditions. In this regard, ATCO noted that subsection 5(4) of Section 9 of the tariff states that the ISO must allocate the participant-related costs of transmission facilities used to provide system access services to more than one market participant at a single substation to the market participants at the substation by utilizing the substation fraction for each market participant. However, the ATCO Electric panel explained during the oral hearing that the DFO is the market participant for both load customers and the DCG at each POD.<sup>925</sup> Accordingly, ATCO submitted that as there is only one market participant for both DTS and STS contracts at a POD (except customers who have been granted the right to take service directly from the AESO under Section 101 of the *Electric Utilities Act*), the AESO's terms and conditions do not require a substation fraction to be created.<sup>926</sup>

817. In its argument, ENMAX submitted that the AESO has acknowledged that it is up to DFOs to determine how they will pass on DTS and STS costs arising from the AESO's proposed new policy. Consequently, the AESO cannot unilaterally achieve its objective of treating DCG and transmission-connected generation on an equal footing. ENMAX indicated that it anticipates that the question of how DFOs pass on STS and DTS costs associated with DCGs will be discussed as part of the Commission's Distribution System Inquiry.<sup>927</sup>

818. The AESO argued in reply that costs that are deemed to be supply-related should be flowed through, at least to some extent, to DCGs that require support from the transmission system to supply load, and that they will therefore benefit from a more reliable connection to the transmission system.<sup>928</sup> However, the AESO submitted that if the substation fractioning formula creates issues from a distribution perspective, such issues should be considered to be a distribution matter that should be addressed as part of a distribution tariff proceeding. The AESO considered that DFOs, such as Fortis, are in the best position to assess how connection project costs should be allocated among their respective end-use customers.<sup>929</sup>

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<sup>923</sup> Transcript, Volume 7, page 1130 lines 16-22 (Mr. Stroh).

<sup>924</sup> Exhibit 22942-X0560, CGWG argument, paragraphs 82-83.

<sup>925</sup> Transcript, Volume 5, pages 906-907.

<sup>926</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 61.

<sup>927</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 9.

<sup>928</sup> Exhibit 22942-X0558, AESO argument, paragraph 93-94, PDF pages 36-37, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 76.

<sup>929</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 76.

819. Given the foregoing, the AESO disagreed with Fortis's suggestion that the AESO's ability to reassess a contribution decision in certain circumstances<sup>930</sup> creates an "immitigable risk" for Fortis's DCG customers. The AESO's disagreement with Fortis regarding Fortis's duty to flow-through arose from the fact that Fortis treats supply-related costs as if they are "local interconnection costs" that are the subject of the *Transmission Regulation*.<sup>931</sup> The AESO noted that this interpretation is reflected in the testimony of Mr. Stroh, on behalf of Fortis during the oral hearing, as follows:

It's been a longstanding practice within the industry to flow through local interconnection costs associated with supply or generation. And that's consistent with section 28 of the transmission regulation, which requires the AESO to determine what portion of local interconnection costs are allocated to supply, STS, versus demand, DTS.<sup>932</sup> [emphasis added by the AESO]

820. The AESO submitted that although sections 28(1)(a) and 47(b) of the *Transmission Regulation* require the AESO to deem costs as either demand-related or participant-related in instances where there is a DTS and STS contract at the same POD,<sup>933</sup> when a request for system access service is received from a DFO, the market participant at issue is not the owner of a generating unit, and the request does not involve the connection of a generating unit directly to the transmission system. As a consequence, the costs that have been deemed as supply-related costs in relation to system access service provided to a DFO are properly considered not as "local interconnection costs," but as "costs of the transmission system" that must be wholly charged to the DFO in accordance with Section 47(a) of the *Transmission Regulation*.<sup>934</sup> Consequently, Fortis cannot rely on the "local interconnection cost" provision of the *Transmission Regulation* to justify the flow through of supply-related costs to a DCG. Instead, alignment between the ISO tariff and a DFO's distribution tariff is the paramount consideration for the fair treatment for all market participants, whether they are connected to the transmission system or a distribution system.<sup>935</sup>

### Commission findings

821. The Commission understands that the concern expressed in this proceeding that DCG developers would be subject to ongoing risk that costs of future DFO substation upgrades will be flowed to them via substation fractioning relate, in part, to the interpretation of a Fortis letter dated September 28, 2018,<sup>936</sup> that was introduced onto the record of Proceeding 22942 by CGWG witness Ms. Runge.

822. Ms. Runge articulated her concern in light of the letter during her oral hearing appearance:

The AESO's policy is essentially requiring a distribution-connected generator to write a number of blank cheques on the day it connects, and those can be cashed at any point in

<sup>930</sup> Exhibit 22942-X0559, Fortis argument, paragraph 35, PDF page 15.

<sup>931</sup> Exhibit 22942-X0559, Fortis argument, paragraph 35, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 78.

<sup>932</sup> Transcript, Volume 7, page 1148, line 21 to page 1149, line 7; see also Transcript, Volume 7, page 1130 lines 16-22 and page 1172 lines 15-22.

<sup>933</sup> Exhibit 22942-X0578, AESO reply argument, paragraphs 80-81.

<sup>934</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 81.

<sup>935</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 82.

<sup>936</sup> Exhibit 22942-X0508.

time in the next 20 years. The DCG can't control if the substation is going to be upgraded, why it's going to be upgraded, how much that upgrade would cost, and yet it's going to be responsible for a share of those costs.

Under the environment created by this policy, it's going to be extremely difficult for investors to move forward with DC projects. The risk of future liability will likely be enough to put a halt to a number of these projects.<sup>937</sup>

823. The Commission considers that expectation that the costs of the upgrade projects described in Fortis's September 28, 2018, letter reflect Fortis's interpretation that it is required by the *Transmission Regulation* to flow through local interconnection costs. The Commission does not agree.

824. As noted in Section 7.3.10 above, the Commission agrees with the AESO's view that where the market participant is a DFO rather than a generator at the point of connection to the transmission system, Section 47(a) rather than sections 28(1)(a) and 47(b) of the *Transmission Regulation* apply, with the result that the DFO is not legislatively required to flow through substation fraction amounts arising from application of the adjusted metering practice to DCG connected to the DFO's substation. Accordingly, the Commission considers that DFOs have discretion to limit the amount of AESO contributions flowed through to DCGs through the application of the substation fraction to future DFO substation upgrade projects by retaining some or all of this cost.

825. The Commission notes that as part of the packages of CCDs filed in response to an undertaking,<sup>938</sup> Fortis provided CCDs in respect of a contribution in the amount of \$4,998,427 for upgrades at the Hayter 477S substation. While Fortis's response to FAI-AUC-2019APR12-001(b)<sup>939</sup> in this proceeding appears to indicate that Fortis determined STS substation fraction amounts arising from the STS contract capacity increases requested by BluEarth, the Commission does not have sufficient evidence on the record of this proceeding to confirm that the STS amounts shown in FAI-AUC-2019APR12-001(b) were flowed through to BluEarth.<sup>940</sup> The Commission notes that the \$4,998,427 AESO contribution amount is part of the reconciliation of AESO contributions currently under consideration in Proceeding 24281.<sup>941</sup>

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<sup>937</sup> Transcript, Volume 4, page 754.

<sup>938</sup> Exhibit 22942-X0539.

<sup>939</sup> Exhibit 22942-X0541.

<sup>940</sup> Exhibit 22942-X0539. The Commission notes that stage 6 customer contribution decision #1 dated March 8, 2016, shows that an expenditure of \$4,998,437 was initially assigned 100 per cent to DTS (Exhibit 22942-X0539, PDF page 14). Subsequently, the AESO prepared CCD updates dated May 4, 2017 (Exhibit 22942-X0539, PDF pages 34-45), June 2, 2017 (Exhibit 22942-X0539, PDF pages 46-51), and October 17, 2017 (Exhibit 22942-X0539, PDF pages 53-59) related to the same \$4,998,437 expenditure but applying the effect of the substation fraction formula in respect of STS contract increases to 10 MW, 20MW, and 25.3MW, respectively (see Exhibit 22942-X0539, PDF pages 41, 50, and 57). The CCD reflecting the STS contract capacity increases changed the allocation of AESO contribution amounts between DTS and STS but did not trigger any refund or collection by the AESO. By the time of the October 17, 2017, CCD, the allocation of the \$4,998,437 expenditure was determined to be \$4,998,427 to STS, and zero to DTS (see Exhibit 22942-X0539, PDF page 57). The AESO prepared a CCD dated October 15, 2018 in respect of a total expenditure of \$4,991,412 for Hayter 477S upgrades (Exhibit 22942-X0539, PDF pages 74-80) that split the participant-related costs as \$2,818,185 DTS and \$2,173,227 STS (Exhibit 22942-X0539, PDF 78).

<sup>941</sup> Proceeding 24281, FortisAlberta Inc. Capital Tracker True-up Application for the 2016 and 2017 AESO Contributions Program



826. Given this, if the Commission determines that Fortis did not flow through STS amounts arising from the application of the substation fraction to STS contract capacity updates, to BluEarth and, instead, included all or a significant portion of the \$4,998,427 amount within the AESO contribution amounts included in the 2016-2017 true-up, this could mean that Fortis could have K-bar revenue associated with AESO contribution amounts during the second generation of PBR that could, in whole or in part, be used to offset the cost of substation fraction amounts that may arise from future upgrades at Fortis substations. If so, the Commission may take this into account when considering the reasonableness of Fortis's proposals to flow through the STS portion of AESO contributions on future Fortis substation upgrade projects to connected DCGs when this matter is considered in the context of future Fortis tariff proceedings.

827. In light of the concern articulated by Ms. Runge that uncertainty with respect to the flow-through of substation fraction amounts arising from future DFO substation upgrades may affect future DCG developments, the Commission considers that it is the responsibility of the DFOs to ensure that DCG developers are made aware of the DFO's plans in respect of the flow through of future substation upgrade costs in light of the Commission's determinations in this decision.

### **7.3.11 Other matters**

#### **7.3.11.1 DFO metering costs and complexity of implementation**

828. ENMAX argued that the AESO should not proceed with its adjusted metering practice given a number of remaining uncertainties that ought to be examined in a proceeding like the Commission's Distribution System Inquiry. In particular, it submitted that immediate implementation of the proposed tariff changes could trigger material investments in metering infrastructure and billing systems that could be unnecessary if future expected market and tariff developments would not have required these investments to be made. As such, implementing the AESO's adjusted metering practice imposes undue costs on rate-payers and undue risks to distribution utilities.<sup>942</sup>

829. The DGWG asserted that the AESO is discounting the significant extra cost burden imposed on ratepayers for TFOs to add metering, process data and produce reconciliations at the feeder level which has the potential to require many times the number of meters than the existing process. The DGWG submitted that the increase in both capital costs and ongoing operational costs would be substantial.<sup>943</sup> It added that the AESO's decision not to provide a response to its IR requesting the AESO to provide an analysis of DFO feeder level revenue-class metering and the costs to equip meters without revenue class metering, due to the effort involved,<sup>944</sup> demonstrates that the AESO does not have any understanding of the effort required to implement its proposed changes.<sup>945</sup> Moreover, because it is a DFO matter, the AESO should not be speculating as to the effort involved in implementing ID 2018-019T.<sup>946</sup>

830. In argument, the AESO submitted that because DFOs already administer the determination of contractual obligations and the location of ISO tariff charges across multiple services served by a single substation, its implementation of the adjusted metering practice

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<sup>942</sup> Exhibit 22942-X0547, ENMAX argument, paragraphs 12-13.

<sup>943</sup> Exhibit 22942-X0562, DGWG argument, paragraph 13.

<sup>944</sup> Exhibit 22942-X0279, AESO-DGWG-2018NOV01-004(b), PDF page 9.

<sup>945</sup> Exhibit 22942-X0562, DGWG argument, paragraph 38.

<sup>946</sup> Exhibit 22942-X0562, DGWG argument, paragraph 39.

would not result in any more complexity than already exists for DFOs.<sup>947</sup> Responding to the DGWG in reply, the AESO submitted that there was no evidence on the record of the current proceeding from a TFO or otherwise to support the DGWG's claim that the AESO's adjusted metering proposal would require many times the number of meters, or would involve significant extra costs.<sup>948</sup>

### **Commission findings**

831. The Commission notes that ENMAX<sup>949</sup> filed a letter suggesting that there could be additional metering-related costs to implement the AESO's proposed adjusted metering practice. However, the Commission agrees with the AESO's observation that there is no evidence on the record of Proceeding 22942 to suggest that costs incurred by either DFOs or TFOs would be substantial, nor that such costs would outweigh benefits of implementing the AESO's proposed adjusted metering practice.

832. In the absence of evidence to support these claims, the Commission is not persuaded that these unsupported claims warrant a finding to defer consideration of the AESO's adjusted metering proposal in this tariff.

#### **7.3.11.2 Concerns of the University of Alberta**

833. In argument, the U of A indicated that because it is not directly connected to the transmission system, it did not become aware of the AESO's proposal outlined in ID 2018-019T until late in the proceeding.

834. The U of A explained that it operates the U of A electric system within its own defined service territory, and explained that while its system is a net consumer of energy from the AIES, the U of A system supplements AIES energy through the use of energy produced by a district energy system that pre-dated the 1990's-era restructuring. Further, the U of A explained that although its generation source is located behind feeders, any surplus energy that is produced from time-to-time is wheeled through the Garneau low voltage bus to one of the other dedicated U of A system feeders. However, the U of A indicated that in following this practice, it actively manages its system to ensure that energy is not exported to the AIES.

835. The U of A considered that its system is comparable to a direct-connect industrial system, with the exception that it does not use energy for an industrial purpose and that a third party (EPCOR distribution) owns the dedicated feeders. Consequently, the U of A expressed concern that the AESO's proposed adjusted metering practice (which it termed the AESO's gross billing proposal) might apply to it.

836. The U of A submitted that if the AESO's proposed adjusted metering practice is not intended to apply to it, then the AESO should adopt tariff language to clarify this exemption. Conversely, if it is the AESO's intention to apply its proposal to the U of A, the Commission should seek to determine:

- how many current customers the gross billing policy would apply to;
- how much more revenue would be collected; and

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<sup>947</sup> Exhibit 22942-X0558, AESO argument, paragraph 61.

<sup>948</sup> Exhibit 22942-X0558, AESO argument, paragraph 71.

<sup>949</sup> Exhibit 22942-X0161.

- a transition process for the implementation of the new policy.

837. It added that if the AESO's gross billing proposal is expected to apply to them, gross billing would be expected to cost the U of A millions of dollars per year.

838. The U of A submitted that it needs to study whether, as a result of gross billing, it ought to adjust its system to allow transfers without employing the Garneau substation. If so, it indicated that a business case on the desirability of making adjustments to its system may need to be prepared. In addition, it submitted that because potential changes to the U of A system operations could affect EDTI service area reliability, EDTI should be given time to study the effect of gross billing on its system to determine if additional reinforcement will be necessary.

839. In reply, the AESO noted that it is not proposing that the adjusted metering practice be applied to existing sites that are already metered on a gross basis. Given this, the AESO submitted that the U of A's existing load and generation configuration would not be affected by the implementation of the AESO's proposed adjusted metering practice.<sup>950</sup>

### **Commission findings**

840. To the extent that the U of A is not served exclusively by a distribution facility owner, and instead utilizes a unique electrical system that includes services provided by both EDTI and the AESO, the U of A has a responsibility to be aware of changes in authoritative documents, including proposed changes in the ISO tariff.

841. Because the concerns identified by the U of A were not raised until argument and were only addressed on a limited basis by the AESO in reply argument, it is unclear to the Commission whether, or to what extent, the AESO's proposed adjusted metering proposal affects the U of A.

842. In Decision 2012-102, the Commission adopted the findings of its predecessor board regarding the purpose of a compliance filing:

Further, Decision 2006-068 clearly states what the purpose of a compliance filing is:

The purpose of a compliance filing is to provide the utility with an opportunity to reflect the full and interrelated impact of all the Board's findings from the GRA decision in the utility's rates and charges. In a compliance filing, it is inappropriate for a party to introduce new evidence. It is also not the appropriate forum to dispute the Board's decision. If a party believes there are new facts or circumstances that may change the Board's original decision in the GRA, or believes the Board has erred, then the appropriate process for that party to follow is to bring a review and variance application (R&V) of the original decision to the Board.<sup>951</sup>

843. The Commission, as an expert tribunal, employs a rigorous procedural process in its determination of applications before it. In doing so, it also recognizes that tribunals are created to increase the efficiency of the administration of justice. Therefore, in order to consider this matter expeditiously, notwithstanding the usual scope associated with a compliance filing, the

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<sup>950</sup> Exhibit 22942-X0558, AESO argument, paragraph 70.

<sup>951</sup> Decision 2012-102: EPCOR Water Services Inc., Regional Water Customers Group Rates for Water Supplied by EPCOR Water Services Inc. to RWCG for 2004, 2005, 2006 and 2007, April 12, 2012, paragraph 23.

Commission directs the AESO to provide a complete explanation of its understanding of the effect on the U of A of its adjusted metering practice at the time of its refiling application. The U of A will be permitted to file evidence in this refiling application in response to the AESO's filing.

### 7.3.12 Final conclusions

844. The Commission makes the following findings with respect to the AESO's proposed adjusted metering practice set out in subsection 7.3.2 of the AESO's amended application:

- The Commission accepts the AESO's rationale for proposing that the adjusted metering practice apply to distribution connected generation.
- The Commission considers that the adequacy of consultation regarding the AESO's proposed adjusted metering practice prior to the filing of the application did not preclude the Commission's consideration of the AESO's adjusted metering practice in this proceeding. Parties had a full opportunity to present their evidence on the AESO's proposed adjusted metering practice in this proceeding.
- The Commission finds the AESO's proposal is consistent with applicable legislation.
- The Commission finds that public interest considerations raised by proponents for the promotion of renewable forms of generation should not take precedence over the need to implement the AESO's adjusted metering practice to rectify billing determinant erosion and potential cross subsidization of DCG by load.
- The Commission finds that DCGs require access to and obtain benefits from the transmission system. Therefore, it is reasonable to allocate transmission system costs to DCGs, pursuant to applicable legislation with respect to the allocation of costs to STS market participants.
- The Commission finds that DCG does not necessarily provide a one-to-one offset between energy dispatched by DCG and load served by the same distribution substation and that the timing of DCG generation peaks may not correspond to those that drive transmission expansion investments.
- The Commission finds that the continued provision of DCG credits is a distribution tariff matter.
- The Commission finds the AESO's proposal to grandfather the application of its adjusted metering practice to be reasonable and not unduly prejudicial.
- The Commission finds that implementation of the AESO's proposed adjusted metering practice would not give rise to impermissible retroactive rate making concerns.
- The Commission finds that distribution facility owners are not required to flow through costs arising from the implementation of the AESO's adjusted metering practice to DCGs as they pertain to interconnection costs.

- The Commission finds that concerns about the cost or complexity of implementing the adjusted metering practice should not preclude its approval.
- The Commission directs the AESO to address the issues raised by the University of Alberta in the AESO's refiling application pursuant to this decision.

845. Subject to any matter arising following the review of the potential effect of the AESO's adjusted metering practice to be considered in the refiling application proceeding, the AESO's proposed adjusted metering practice is approved.

#### 7.4 Payment in lieu of notice

846. The AESO describes a PILON payment as a financial obligation for load customers that creates the incentive to provide accurate information to the AESO for the purpose of transmission system planning and development decisions. GUOC payments and potential forfeiture of GUOC payments are the financial obligations for generation customers to provide accurate information to the AESO.<sup>952</sup>

847. In argument, DUC et al. recommended that the PILON and advancement costs provisions should be revised to collect only actual costs incurred for connection projects that are cancelled and where no system upgrades are required.<sup>953</sup> It was DUC et al.'s position that the AESO proposal on this matter did not reflect cost causation and was akin to a penalty.

848. DUC et al. further argued that as industrial customers develop projects, they should be afforded the opportunity to initiate the transmission connection process without the obligation to pay for future transmission upgrades that may never be required.<sup>954</sup>

849. DUC et al. concluded by stating that the desire for information certainty does not justify the imposition of fees in excess of actual costs and that the AESO's terms and conditions with respect to the PILON are not commercially reasonable and should not be approved. DUC et al. recommended that the AESO be directed to limit the cost exposure for customers connecting to the grid to the actual costs incurred in order to connect the project.<sup>955</sup>

850. The AESO replied that it was unclear whether DUC et al. were suggesting a change to the current ISO tariff PILON provisions or only referring to the proposed ISO tariff provisions requiring earlier contract execution and effective dates.<sup>956</sup> The AESO added that the AESO's proposal for earlier execution and effective date of SAS agreements will make PILON payments applicable earlier in the connection process, which will align the PILON obligations of current Rate DTS market participants to those participants seeking new system access service (or additional contract capacity).<sup>957</sup>

851. It was further noted by the AESO that it has introduced into the SAS agreement, flexibility by including events which must occur before PILON charges become applicable to participants (conditions precedent). This ensures that the ISO tariff provisions are able to

<sup>952</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 34.

<sup>953</sup> Exhibit 22942-X0543, DUC et al., final argument, PDF page 5.

<sup>954</sup> Exhibit 22942-X0543, DUC et al., final argument, PDF page 38.

<sup>955</sup> Exhibit 22942-X0543, DUC et al., final argument, PDF page 39.

<sup>956</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 32.

<sup>957</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 32.

accommodate matters that the AESO determines to be outside of the market participants control. The AESO is of the view that existing Rate DTS market participants and those seeking new system access service have the same effect on system analysis and planning 30 days post permit and licensing. **Therefore, the AESO stated that a penalty for cancellation, delay or reduction in contract capacity is appropriate at that point in the connection process.**<sup>958</sup>

852. The AESO submitted that subsection 7.3.9 of the amended application explained that an earlier contract effective date provides the AESO with increased confidence that a connection project will proceed since financial obligations of a market participant, which include PILON and GUOC payments, will be triggered following the satisfaction of conditions precedent to execution of an SAS agreement.<sup>959</sup>

853. The AESO concluded by stating that DUC et al. have not provided evidence as to how a payment that only covers actual costs of a transmission project will provide any financial incentive for market participants to provide accurate information, such as operating capacity, to the AESO. The AESO reiterated that subsection 7.3.9 of the amended application, provides a financial obligation to ensure accuracy in forecast information, such as operating capacity, to the AESO and that the currently approved PILON provisions provide this financial incentive, whereas a limited PILON based on realized costs, or actual costs, of transmission projects does not provide any financial incentive.

### **Commission findings**

854. The determination of the quantum of the PILON charges has not changed from the method previously approved by the Commission. The Commission understands that the proposed change to the PILON charges relate to earlier contract execution and effective dates of SAS agreements and the introduction of conditions precedent to increase the flexibility of the ISO tariff provisions.

855. DUC et al. have not provided any evidence nor argument with respect to the earlier contract execution of SAS agreements. Nor has DUC et al. provided arguments with respect to the introduction of conditions precedent for the PILON. **Therefore, the Commission accepts the proposed PILON terms as submitted by the AESO.**

## **7.5 Totalized Billing of Industrial Complexes**

856. The AESO's initial position regarding application of ID 2018-019T to industrial complexes was that ID 2018-019T was not proposed to apply to industrial complexes and instead a market participant should be able to choose between net or gross metering.<sup>960</sup> The AESO defined industrial complexes as those dual-use connections where a market participant has both a Rate DTS and Rate STS service access agreement, but did not make a specific distinction between an industrial complex with an industrial service designation and a site that did not have the designation.<sup>961</sup>

857. The AESO submitted that industrial complexes with combined load and on-site generation must be able to develop their own economic supply of generation to serve their

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<sup>958</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 32.

<sup>959</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 34.

<sup>960</sup> Exhibit 22942-X0014.03, Section 3.6(4).

<sup>961</sup> Exhibit 22942-X0163, paragraph 215.

integrated processes in the most economic manner possible and should be allowed to totalize DTS and STS, irrespective of whether they are connected directly to the transmission system or they are directly connected by way of a SASR submitted by a DFO.<sup>962</sup>

858. In argument, the AESO revised its position regarding the metering of industrial complexes, noting the Commission's recent decision, Decision 23418-D01-2019, regarding an application by EPCOR Water Services Inc. to construct and operate a 12 MW solar power plant primarily to supply EPCOR's E.L. Smith Water Treatment plant, and to export excess electric energy to the AIES. The AESO submitted that, in that decision, the Commission engaged in a review of the legislative scheme for self-supply arrangements in Alberta and noted the "legislature's intention to allow a person to build and operate a generating unit on land a person owns or leases, and to exempt the generating unit and the electric energy produced by it from the statutory scheme if the electric energy is intended only for the person's own use, consumed solely by the person, and solely on the person's property."<sup>963 964</sup>

859. The AESO explained that in light of Decision 23418-D01-2019, totalization would now appear to be inapplicable for industrial complexes that have not obtained an industrial system designation under Section 4 of the *Hydro and Electric Energy Act*, or that are not otherwise subject to an exemption in respect of the energy produced by the industrial complex.<sup>965</sup>

860. The AESO noted that some exemptions are available to the requirements under Section 18(2) of the *Electric Utilities Act*, which stipulates that all electric energy entering or leaving the AIES is exchanged through the power pool, and Section 101 of the *Electric Utilities Act*, which stipulates that a person wishing to obtain electricity for use on property must purchase that electricity from the owner of the electric distribution system for that service area.

861. The AESO submitted that in the absence of an industrial system designation or the owner of the non-designated industrial complex having an exemption, the owner will be required to either:

- (i) Offer into the power pool all produced electric energy, in which case the site would no longer operate as an integrated process; or
- (ii) Not export any electric energy to the AIES, consistent with the "closed-loop" policy applicable to self-supply.<sup>966</sup>

862. In the case of (i) above, the AESO explained that totalizing would be inappropriate as the site will require a Rate STS contract level reflective of the full gross output into the market and a Rate DTS contract level reflective of the system access service required to serve the full gross load. In the case of (ii), the AESO noted that totalizing would be irrelevant as there will be no output to the AIES.<sup>967</sup>

863. The AESO requested that in the event the Commission accepts the AESO's updated position regarding industrial complexes, subsections 3.2(2)(f) and 3.6(4) of the proposed 2018

<sup>962</sup> Exhibit 22942-X0163, paragraph 215.

<sup>963</sup> Decision 23418-D01-2019, paragraph 92.

<sup>964</sup> Exhibit 22942-X0558, paragraph 74.

<sup>965</sup> Exhibit 22942-X0558, paragraphs 75-76.

<sup>966</sup> Exhibit 22942-X0558, paragraph 76.

<sup>967</sup> Exhibit 22942-X0558, paragraph 77.

ISO tariff should be revised to provide that an industrial site will only be able to “choose” totalized metering at a substation if an approval from the Commission has been obtained that permits the export of electric energy to the AIES.<sup>968</sup>

864. In reply argument, the CCA continued to advocate for the principle that when flow at the substation is net load, that load should be associated with a Rate DTS contract and when the flow at the substation is net generation, that generation should be subject to Rate STS requirements, including payments for the substation fraction associated with the net generation and the GUOC.<sup>969</sup>

865. The CCA submitted that an ISD differs from an industrial complex in that the ISD is allowed to totalize load and supply across contiguous properties to reflect a virtual “behind the fence” net metering situation. However, an ISD does not contemplate totalization at the substation level. The CCA noted, Section 4(2)(b)(ii) of the *Hydro and Electric Energy Act* contemplates the efficient exchange of electric energy with the interconnected electric system, that is in excess of the industrial system’s own requirements and that there is nothing in the ISD legislation that says the exchange of energy with the interconnected electric system should be exempt from responsibility for STS charges.<sup>970</sup>

866. The CCA recommended that irrespective of whether it is an ISD or an industrial complex, totalization “behind the fence” should be allowed. However, totalization at the substation level should not be permitted for ISDs or industrial complexes on a go-forward basis in order to be consistent with the principles of ID 2018-019T.<sup>971</sup>

867. Fortis submitted that the AESO’s proposed metering practice will discriminate between market participants because an industrial site may have the opportunity to choose totalized metering at a substation while a DFO will not be afforded this choice and no credible rationale was offered for the “discriminatory implementation of the adjusted metering practice.”<sup>972</sup>

### Commission findings

868. A number of provisions deal with on-site generation developed for the express purpose of self-supply, including Section 2(1)(b) of the *Electric Utilities Act*, Section 13 of the *Hydro and Electric Energy Act*, Section 6 of the *Isolated Generating Units and Customer Choice Regulation* and Section 2(f)(i) of the *Fair, Efficient and Open Competition Regulation*. In Decision 23418-D01-2019, the Commission provided an in-depth and comprehensive review of the legislative scheme for self-supply arrangements in Alberta.<sup>973</sup>

869. In that decision, the Commission found EPCOR Water’s proposal, which was to consume directly approximately 70 per cent of its proposed power plant’s annual output on-site, and export the remaining 30 per cent to the wholesale market, to be inconsistent with sections 18 and 101 of the *Electric Utilities Act* and Section 2(f) of the *Fair, Efficient and Open Competition Regulation*.<sup>974</sup> In that decision, the Commission also considered that the exemption in

<sup>968</sup> Exhibit 22942-X0558, paragraph 78.

<sup>969</sup> Exhibit 22942-X0567, paragraphs 10-14.

<sup>970</sup> Exhibit 22942-X0567, paragraph 17.

<sup>971</sup> Exhibit 22942-X0567, paragraph 18.

<sup>972</sup> Exhibit 22942-X0579, paragraph 41(c).

<sup>973</sup> Decision 23418-D01-2019, Section 6.2.

<sup>974</sup> Decision 23418-D01-2019, paragraph 75.



Section 2(1)(b) of the *Electric Utilities Act* did not apply to the power plant because the electric energy produced by the power plant would not be consumed solely by EPCOR Water and solely on EPCOR Water's property.<sup>975</sup> The principles established in Decision 23418-D01-2019 are applicable to this proceeding.

870. The Commission finds the exemption in Section 2(1)(b) would not apply to an industrial complex because these sites are not closed loop in nature, use market infrastructure and transact in the market. Therefore, industrial complexes that have not obtained an exemption under Section 4 of the *Hydro and Electric Energy Act* must be gross metered. The Commission agrees with the AESO and finds that totalization is inapplicable for industrial complexes that have not obtained an industrial system designation.

871. Industrial system designations are industrial complexes that have applied for the designation and have met prescriptive eligibility requirements under Section 117 of the *Electric Utilities Act* and the criteria under Section 4 of the *Hydro and Electric Energy Act*. Totalization or net metering is specifically contemplated by Section 4(2)(b)(ii) of the *Hydro and Electric Energy Act*, which states:

4(2) Where the Commission is considering an application for designation as an industrial system, the Commission shall have regard to the following principles:

...

(b) the designation must support

...

(ii) the efficient exchange, with the interconnected electric system, of electric energy that is in excess of the industrial system's own requirements, ....

872. Therefore, the Commission finds that totalization or net metering is allowed for a site that has obtained an industrial service designation.

873. In its compliance filing the AESO is directed to file any changes that are necessary to the ISO tariff to comply with the Commission's findings in this section.

874. Because the AESO's revised position on this issue was brought forward in argument, the Commission does not have enough information to make determinations with respect to other exemptions or approvals for dual-use customers or industrial complexes. If there are other issues regarding the metering of industrial complexes and specific exemptions or approvals available to industrial complexes, the AESO is directed to identify these and, if necessary, propose and justify amendments to its tariff in its compliance filing.

## 8 Terms and conditions: construction contributions

875. The AESO's construction contribution policy, including the principles supporting it, its methodology and its investment levels have consistently been the subject of contention in ISO tariff proceedings.

<sup>975</sup> Decision 23418-D01-2019, paragraph 81.

876. A construction contribution is the financial contribution in aid of construction (CIAC) in excess of the available investment by the AESO (the maximum investment level) that a market participant must pay for the construction and associated costs of transmission facilities required to provide system access service. Construction contributions are intended to balance the economic effects of connecting a new customer between existing customers and the new customer.<sup>976</sup>

877. In Decision 2012-362, the Commission stated that the AESO's contribution policy should "exert an economic discipline on siting decisions by sending price signals, reflective of the AESO's economics, to connecting customers."<sup>977</sup> Further, the Commission determined that providing this price signal should be the primary policy objective of the contribution policy.<sup>978</sup> The Commission reaffirmed this priority in Decision 2014-242.<sup>979</sup>

878. In this proceeding, AltaLink filed evidence requesting changes to the way in which the AESO's customer contribution policy is accounted for as between the DFOs and the TFOs. The AESO has proposed no changes to its current customer contribution policy. Fortis has also filed evidence addressing this issue. It opposes AltaLink's suggested changes and supports the AESO's current customer contribution policy accounting practice.

## **8.1 AltaLink contribution proposal**

### **8.1.1 History of AltaLink contribution proposal**

879. As part of its 2017-2018 GTA, Proceeding 21341, AltaLink included a proposal that would involve a refund of construction contributions paid by Fortis. AltaLink put forward this proposal to address AltaLink's view that the accounting treatment of AESO contributions, which effectively reduces AltaLink's rate base, is unfair to AltaLink for reasons set out in AltaLink's application.<sup>980</sup>

880. Fortis filed a motion in Proceeding 21341 that objected to AltaLink's proposal.<sup>981</sup> After a process to consider Fortis's motion, the Commission issued a ruling on August 30, 2016,<sup>982</sup> which directed AltaLink to remove those sections dealing with its proposed treatment of Fortis's contributions from its 2017-2018 GTA.

881. On December 15, 2017, the Commission received a submission from AltaLink<sup>983</sup> in which AltaLink indicated that it intended to file evidence in respect of the treatment of AESO contributions made by Fortis. As part of its submission, AltaLink requested that the Commission not schedule IRs until the end of January 2018 to allow AltaLink sufficient time for discussion with the AESO and other parties on the matter. The Commission requested comments from parties in respect of AltaLink's request in correspondence dated December 21, 2017.<sup>984</sup>

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<sup>976</sup> Decision 2012-362: Alberta Electric System Operator, 2012 Construction Contribution Policy, Proceeding 1162, December 28, 2012, paragraph 11.

<sup>977</sup> Decision 2012-362, paragraph 36.

<sup>978</sup> Decision 2012-362, paragraph 40.

<sup>979</sup> Decision 2014-242, paragraph 527.

<sup>980</sup> Proceeding 21341, Exhibit 21341-X0011, Section 31.4.

<sup>981</sup> Exhibit 21341-X0021.

<sup>982</sup> Exhibit 21341-X0047.

<sup>983</sup> Exhibit 22942-X0098.

<sup>984</sup> Exhibit 22942-X0104.

882. On January 19, 2018, the Commission issued a letter that included comments regarding AltaLink's concerns regarding the treatment. In that letter, the Commission ruled that AltaLink's contribution issues could be considered in Proceeding 22942.<sup>985</sup>

883. On April 30, 2018, following a consultation process directed by the Commission which included consideration of AltaLink's contribution issues, the AESO filed a letter<sup>986</sup> in which it provided an overview of its determinations for its application in light of those consultations. As part of that correspondence, the AESO explained that it did not intend to make any amendments to its 2018 tariff application to address the contribution issues that had been discussed in the consultations.

884. Following the AESO's filing of its amended application, on January 15, 2019, AltaLink filed evidence setting out its contribution proposal.<sup>987</sup>

885. On January 25, 2019, the Commission received correspondence from Fortis requesting that the Commission provide it with the right to file reply.<sup>988</sup> Following the receipt of submissions on this request from AltaLink<sup>989</sup> and a further submission by Fortis,<sup>990</sup> the Commission issued a ruling on January 30, 2019,<sup>991</sup> that authorized Fortis to file evidence and then provided an opportunity for this evidence to be examined in IRs from the AESO, the Commission and AltaLink. In accordance with this revised schedule, Fortis filed its evidence on February 11, 2019. IRs on Fortis's evidence were filed by the AESO, the Commission and AltaLink on February 19, 2019. Fortis provided responses to these IRs on February 26, 2019.<sup>992</sup>

886. On February 27, 2019, AltaLink<sup>993</sup> requested an opportunity to file rebuttal evidence in response to the evidence filed by Fortis. In a ruling dated March 1, 2019,<sup>994</sup> the Commission granted AltaLink's request. In the ruling, the Commission set out a schedule for the receipt of the AESO's rebuttal evidence and for AltaLink to file its rebuttal to the Fortis evidence. In accordance with the ruling, the AESO's rebuttal evidence<sup>995</sup> was filed on March 6, 2019. AltaLink's rebuttal evidence<sup>996</sup> was filed on March 8, 2019.

887. On May 22, 2019, AltaLink<sup>997</sup> requested leave to file sur-reply argument in light of its concerns about certain submissions regarding AltaLink's contribution proposal in reply argument filed by Fortis. After issuing a process letter to consider this request,<sup>998</sup> the Commission received submissions from Fortis<sup>999</sup> and AltaLink<sup>1000</sup> on May 31, 2019, and June 6, 2019, respectively.

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<sup>985</sup> Exhibit 22942-X0112.

<sup>986</sup> Exhibit 22942-X0129.

<sup>987</sup> Exhibit 22942-X0342, Exhibit 22942-X0343, Exhibit 22942-X0344, Exhibit 22942-X0345.

<sup>988</sup> Exhibit 22942-X0346.

<sup>989</sup> Exhibit 22942-X0371.

<sup>990</sup> Exhibit 22942-X0372.

<sup>991</sup> Exhibit 22942-X0374.

<sup>992</sup> Exhibits 22942-X0434 to 22942-X0439.

<sup>993</sup> Exhibit 22942-X0440.

<sup>994</sup> Exhibit 22942-X0441.

<sup>995</sup> Exhibit 22942-X0447.

<sup>996</sup> Exhibit 22942-X0451.

<sup>997</sup> Exhibit 22942-X0582.

<sup>998</sup> Exhibit 22942-X0585.

<sup>999</sup> Exhibit 22942-X0586.

<sup>1000</sup> Exhibit 22942-X0587.

888. On June 14, 2019, the Commission issued a ruling<sup>1001</sup> that granted AltaLink's request to file sur-reply argument. AltaLink's sur-reply was filed on June 24, 2019, in accordance with this ruling.<sup>1002</sup>

### 8.1.2 Mechanics of AltaLink contribution proposal

889. In its evidence, AltaLink described the basic mechanics of its proposal as follows:

- The DFO pays a customer contribution to the TFO as provided for under the current AESO customer contribution policy.
- The TFO returns the customer contribution to the AESO.
- The AESO then returns the customer contribution to the DFO.
- The DFO is billed by the AESO for the TFO's revenue requirement associated with the transferred investment.
- The AESO applies this revenue as an offset to its tariff, thereby keeping distribution and transmission customers whole.<sup>1003</sup>

890. In addition, AltaLink explained that:

- its contribution proposal would only apply to the unamortized, DFO-only contributions as at December 31, 2017;
- the unamortized balances would be refunded to the AESO, who would, in turn, pass them on to the DFO;
- the AESO would charge the DFO on a monthly basis for the TFO's costs of service associated with the transferred contributions;
- the DFO would collect monthly charges from its customers; and
- the DFO would pay to the AESO, the monthly charges collected from its customers.<sup>1004</sup>

891. AltaLink submitted that its proposal does not change the AESO's contribution policy, nor does it change who pays the contribution. It submitted that this is appropriate because it is the DFO end-use customer who causes the transmission facility addition and, therefore, the DFO end-use customer should pay the contribution.<sup>1005</sup>

892. AltaLink proposed that it would perform the accounting and prepare the requisite monthly calculation on behalf of the AESO to assist with the implementation of this proposal.<sup>1006</sup>

#### 8.1.2.1 Legal considerations

893. AltaLink and Fortis each presented several legal arguments in support of their respective positions. The Commission's consideration of the issues raised is presented under separate subheadings below.

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<sup>1001</sup> Exhibit 22942-X0588.

<sup>1002</sup> Exhibit 22942-X0589.

<sup>1003</sup> Exhibit 22942-X0342, paragraph 122.

<sup>1004</sup> Exhibit 22942-X0342, paragraph 123.

<sup>1005</sup> Exhibit 22942-X0342, paragraph 125.

<sup>1006</sup> Exhibit 22942-X0342, paragraph 130.

### 8.1.2.2 Do prior Commission determinations preclude further consideration of AltaLink's contribution policy proposal?

894. Fortis submitted in its argument that AltaLink's contribution proposal has been considered and denied in prior proceedings. Fortis noted that similar AltaLink contribution proposals have been brought forward since 2005 and have been rejected by the Commission or its predecessor.<sup>1007</sup> It submitted that the reasons for AltaLink's proposal being denied in the prior proceedings remain valid today.<sup>1008</sup>

895. Fortis argued that although the form of AltaLink's current proposal may have changed from past proposals, its substance has not. Fortis submitted that AltaLink's proposal in the current proceeding is essentially the same as the proposal in AltaLink's 2017-2018 GTA. In that proceeding, the Commission determined that there was no reasonable prospect that the contribution policy proposal advanced by AltaLink could satisfy the legislative scheme.<sup>1009</sup> It added that the only difference from that proposal and the current proposal is that AltaLink now proposes to flow funds through the AESO tariff as a means of circumventing the Commission's prior ruling. However, it claimed that AltaLink has failed to advance any credible rationale as to why there should be discriminatory treatment as between direct connect customers and a DFO.

896. In its sur-reply argument, AltaLink contended that its proposal in this proceeding is fundamentally different from its proposal in Proceeding 21341. Therefore, the Commission's ruling in Proceeding 21341 is irrelevant. AltaLink noted that its proposal in Proceeding 21341 was brought forward in the context of AltaLink's own tariff. AltaLink submitted that the proposal it presented in Proceeding 21341 was rejected because the Commission found that customer contributions are governed by the ISO tariff, not by AltaLink's tariff. Furthermore, the Commission found that there was "no reasonable prospect" that AltaLink's Proceeding 21341 contribution could satisfy the legislative scheme because the Commission determined that a tariff relationship between Fortis and AltaLink did not exist under the legislation.<sup>1010</sup>

897. In contrast, AltaLink submitted that its proposal in the current proceeding does not depend on a tariff relationship between Fortis and AltaLink. Rather, the current proposal takes the form of a rider that would apply to all DFOs. Given this, AltaLink submitted that the concerns that led to the Commission's ruling in Proceeding 21341 do not arise.<sup>1011</sup>

### Commission findings

898. The Commission's past considerations of the customer contribution issue raised by AltaLink does not preclude the Commission from considering AltaLink's most recent proposal in this proceeding.<sup>1012</sup>

<sup>1007</sup> Exhibit 22942-X0420, AML-FAI-2019JAN28-001, cited at Exhibit 22942-X0559, paragraph 14.

<sup>1008</sup> Exhibit 22942-X0559, Fortis argument, paragraph 13(a).

<sup>1009</sup> Exhibit 22942-X0579, paragraph 17, citing Exhibit 21341-X0047, AUC Letter, Commission Ruling on procedural motion to strike sections 8.1.4 and 31.4 from AltaLink's application, August 30, 2016, paragraphs 22 to 27.

<sup>1010</sup> Exhibit 22942-X0589, paragraph 4, citing Exhibit 21341-X0047, AUC Letter, Commission Ruling on procedural motion to strike sections 8.1.4 and 31.4 from AltaLink's 2017-2018 GTA application, August 30, 2016, paragraphs 22-27.

<sup>1011</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 5.

<sup>1012</sup> *ENMAX Energy Corporation v Alberta Utilities Commission*, 2019 ABCA 222, paragraphs 55-56.

899. The Commission agrees with AltaLink's interpretation that the fundamental shortcoming of AltaLink's Proceeding 21341 proposal was overcome when AltaLink formulated its contribution proposal as a proposal for unique treatment of contributions arising from Fortis transmission connection projects under the ISO tariff.

900. Given the foregoing, the Commission has assessed the merits of AltaLink's contribution proposal in detail in this decision.

### **8.1.2.3 Is the current treatment of customer contributions consistent with the statutory scheme?**

901. AltaLink submitted that in the *Stores Block*<sup>1013</sup> decision, the Supreme Court of Canada determined that regulatory tribunals do not have unfettered discretion to protect the public interest by imposing conditions or orders contrary to the underlying statutory scheme.<sup>1014</sup>

902. In its argument, AltaLink submitted that the current treatment of Fortis contributions is inconsistent with the legislative scheme because it fails to reflect the costs eligible for inclusion in transmission and distribution rates.<sup>1015</sup> Specifically, AltaLink indicated that it believes that the statutory framework governing electric utilities in Alberta sets out a "rigid and mutually exclusive distinction between transmission and distribution functions," and that this distinction has the effect of restricting transmission and distribution tariffs to the recovery of costs related to transmission systems and distribution systems, respectively. As a result of this statutory interpretation, AltaLink submitted that a DFO is precluded from recovering costs associated with transmission facilities through its tariff.<sup>1016</sup>

903. AltaLink submitted that the statutory scheme makes transmission facilities and distribution systems mutually exclusive. In this regard, AltaLink noted that:

- the definition of "transmission facility" in the *Electric Utilities Act* specifically excludes generating units or electric distribution systems<sup>1017</sup>
- the *Hydro and Electric Energy Act* definition of "transmission line," while largely technical, specifically excludes a power plant or an electric distribution system<sup>1018</sup>
- the *Electric Utilities Act* definition of "electric distribution system" defines "electric distribution system" to exclude "a generating unit or a transmission facility"<sup>1019</sup>
- the *Hydro and Electric Energy Act* definition of "electric distribution system" excludes "a power plant or transmission line."<sup>1020</sup>

904. AltaLink submitted that the above definitions are significant because tariff filing duties and other obligations under the *Electric Utilities Act* are assigned according to ownership. That

<sup>1013</sup> *ATCO Gas & Pipelines Ltd v Alberta (Energy & Utilities Board)*, 2006 SCC 4 (CanLII).

<sup>1014</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 45-46.

<sup>1015</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 30.

<sup>1016</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 33.

<sup>1017</sup> *Electric Utilities Act*, s. 1(1)(bbb), cited at Exhibit 22942-X0555, AltaLink argument, paragraph 34.

<sup>1018</sup> RSA 2000, c H-16, s. 1(1)(o), cited at Exhibit 22942-X0555, AltaLink argument, paragraph 35.

<sup>1019</sup> *Electric Utilities Act*, s. 1(1)(m), cited at Exhibit 22942-X0555, AltaLink argument, paragraph 35.

<sup>1020</sup> *Hydro and Electric Energy Act*, s. 1(1)(b), cited at Exhibit 22942-X0555, AltaLink argument, paragraph 34.

is, to an “owner of a transmission facility”<sup>1021</sup> as distinct from the “owner of an electric distribution system.”

905. AltaLink submitted that the rate making powers of TFOs and DFOs must be considered in light of the distinctions between the distribution and transmission functions discussed above.<sup>1022</sup> It referenced section 122 of the *Electric Utilities Act*, focusing on subsections (b) and (h) in support of its position.

906. AltaLink submitted that subsections 122(1)(b) and (h) must take into account that:

- the *Electric Utilities Act* requires “each owner” of an electric utility to file a tariff;<sup>1023</sup>
- the provisions governing the respective DFO and TFO tariffs clearly set out their purposes;<sup>1024</sup>
- all of these provisions are fundamentally informed by the express legislative distinction between transmission and distribution; and<sup>1025</sup>
- under Section 37 of the *Electric Utilities Act*, a TFO’s tariff sets out the rate to be paid to the AESO “for the use of the owner’s transmission facilities,” to the exclusion of any electric distribution systems.<sup>1026</sup>

907. Considering the above, AltaLink submitted that Section 122(1)(b) only allows DFO tariffs to recover costs and expenses associated with services provided “by means of the owner’s electric distribution system.” Similarly, AltaLink submitted that Section 122(1)(h) does not provide blanket authority for a DFO to include “any other prudent costs”<sup>1027</sup> within its tariff.

908. In its argument, EDTI agreed with AltaLink’s evidence<sup>1028</sup> that AltaLink’s contribution proposal is consistent with the statutory framework established under the *Electric Utilities Act*, which sets a clear distinction between distribution and transmission assets, including for the purposes of setting DFO and TFO rates.

909. In reply argument, Fortis submitted that the AESO’s current contribution regime has always been consistent with the *Electric Utilities Act*, and with the legislative scheme. Fortis noted that the current contribution policy has a long history, and that the policy of providing comparable treatment between direct connect market participants and DFOs has been in place since 2001.<sup>1029</sup>

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<sup>1021</sup> AltaLink cited section 37 of the *Electric Utilities Act* as the source of the obligation of a TFO to file a tariff and *Electric Utilities Act*, s. 37 (obligation of TFO to file a tariff) and the duties of TFO as set out in Section 39 of the *Electric Utilities Act* at Exhibit 22942-X0555, AltaLink argument, paragraph 35.

<sup>1022</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 41.

<sup>1023</sup> *Electric Utilities Act*, section 119, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 43.

<sup>1024</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 43.

<sup>1025</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 43.

<sup>1026</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 44.

<sup>1027</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 44.

<sup>1028</sup> Exhibit 22942-X0342, AltaLink evidence, paragraph 131, cited at Exhibit 22942-X0550, EDTI argument, paragraph 122, bullet 1.

<sup>1029</sup> Decision 2012-362, paragraph 69, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 9.

910. Further, Fortis noted that despite the multiple proceedings that have considered the current contribution policy,<sup>1030</sup> it was not aware of any applications to the Commission for review and variance, or to the Alberta Court of Appeal, that sought a determination that the current contribution policy is inconsistent with the *Electric Utilities Act* or with the applicable legislative scheme.<sup>1031</sup>

911. Fortis submitted that it does not dispute that AltaLink owns the underlying transmission facilities, that AltaLink owns the relevant electric distribution system facilities and that it has no ownership interest in AltaLink's transmission facilities. Notwithstanding these acknowledgments, Fortis considered AltaLink's application of the definitions of "owner" "transmission facility" and "electric distribution system" to the contribution issue to be erroneous.<sup>1032</sup>

912. Fortis acknowledged that AltaLink faces various risks related to the underlying transmission facilities subject to contributions.<sup>1033</sup> However, because contributions do not, and are not intended to either grant rights or impose risks, the existence of these risks on the TFO are irrelevant to the contribution issue. In this regard, Fortis noted that just as Fortis pays a contribution on AltaLink facilities but receives no ownership interest, Fortis's end-use customers receive no ownership interest in Fortis's facilities when they are required to provide a contribution towards facilities required to connect to Fortis's system.<sup>1034</sup>

913. Responding to AltaLink's comments regarding the effect of tariff obligations set out in Section 122(1) of the *Electric Utilities Act*, Fortis submitted that the position of AltaLink conflates the issue of ownership with tariff setting obligations.

914. Fortis noted that under Section 122(1)(a) of the *Electric Utilities Act*, the Commission is required to have regard for the principle that the owner of an electric utility should be provided a reasonable opportunity to recover "costs and expenses associated with capital related to the owner's investment in the electric utility." Considering this argument, Fortis submitted that while it agreed that AltaLink is entitled to costs and expenses associated with its capital investment in transmission facilities, the current contribution policy is consistent with this.

915. In particular, Fortis noted that, as a result of its customer contributions to the AESO, the capital that AltaLink is required to invest is decreased. Fortis emphasized that the effect of AltaLink's required capital investment is the same whether the contribution is provided by a direct-connect market participant, or by a DFO.

916. Fortis submitted that AltaLink's interpretation that the definitions of "owner," "transmission facility" and "electric distribution system" have the effect of entitling only the TFO to costs and expenses associated with transmission facilities is contrary to Section 122(1)(b) of the act. Fortis submitted that as it is required to make capital contributions under the ISO tariff, such contributions are costs and expenses associated with transmission and the AESO's

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<sup>1030</sup> Exhibit 22942-X0424, Fortis evidence, pages 5-38, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 10.

<sup>1031</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 10.

<sup>1032</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 10.

<sup>1033</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 14, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 12.

<sup>1034</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 12.



provision of system access service. Given this, Fortis submitted that Section 122(1)(b) expressly allows the cost of customer contributions to be included within Fortis's tariff.

### Commission findings

917. In its consideration of AltaLink's submissions concerning the legislative provisions raised, the Commission has employed the well-accepted analysis that considers the purpose and scheme of the legislation and the consequences of adopting the ordinary meaning. In this regard, interpretations that are consistent with or promote the legislative purpose should be preferred and interpretations that defeat or undermine the legislative purpose should be avoided.

918. Applying this approach, the Commission is not persuaded that AltaLink's interpretation of the definitions it notes in its argument preclude a DFO from making a contribution under the AESO's tariff or from earning a return on the contribution.

919. Under Section 47(a) of the *Transmission Regulation*, the Commission must ensure that when approving an ISO tariff under Section 122 of the *Electric Utilities Act*:

- (i) the just and reasonable costs of the transmission system are wholly charged to DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and
- (ii) the amount payable by a DFO is recoverable in the DFO's tariff,

920. In consideration of this provision, when read together with the act, it would not be reasonable to apply AltaLink's narrow interpretation of the legislation.

921. Accordingly, the Commission does not find that the current treatment of Fortis's contributions is inconsistent with the legislative scheme.

#### 8.1.2.4 Fortis proposition that electric distribution service provides a conduit for system access service

922. In its evidence,<sup>1035</sup> Fortis explained that it considers that distribution tariffs include both transmission and distribution components. It referred to Section 2(1) of the *Distribution Tariff Regulation*. This provision specifically includes a requirement that a distribution tariff include a separate charge for system access service. In its view, the duty to prepare a distribution tariff in Section 102(1) of the *Electric Utilities Act* includes both distribution and system access service (i.e., a transmission component).

923. Fortis also explained in its evidence<sup>1036</sup> that the duties of DFOs set out in Section 105(1) of the *Electric Utilities Act* include:

- a duty "to arrange for the provision of system access service to customers in that service area," (Section 105(1)(d)); and
- a duty "to undertake financial settlement with the Independent System Operator for system access service." (Section 105(1)(h)).

<sup>1035</sup> Exhibit 22942-X0424, Section 2.3.

<sup>1036</sup> Exhibit 22942-X0424, Section 2.2.

924. Further, it asserted that the definition of “electric distribution service” in the *Electric Utilities Act* “includes any services the owner of the electric distribution system is required to provide by the Commission or is required to provide under this Act or the regulations.”<sup>1037</sup> On this basis, Fortis submitted that, by definition, “electric distribution service” includes and provides a conduit for “system access service,” which is transported by means of an electric distribution system.<sup>1038</sup>

925. Fortis submitted that the requirement that DFOs serve as a conduit for the arrangement and settlement of transmission service reflects a deliberate decision by the drafters of the act to require harmonized treatment between end-use customers. Accordingly, requiring a DFO to pay a customer contribution against the cost of transmission facilities sends a signal to the DFO to propose the right mix of transmission and distribution facilities when deciding how to extend service to end-use customers.<sup>1039</sup>

926. In its evidence, Fortis also expressed concern that differentiating between direct-connect customers and DFOs under the AESO tariff, could provide incentives to engage in “tariff shopping” by certain types of market participants.<sup>1040</sup>

927. AltaLink rejected Fortis’s proposal that DFOs serve as a conduit to provide system access service. It referred to Section 28 of the *Electric Utilities Act*, which states that “The Independent System Operator is the sole provider of system access service on the transmission system.” Consequently, a DFO cannot be a provider of system access service as a component of distribution access service.<sup>1041</sup>

928. AltaLink submitted that the DFO’s duties related to the provision of system access service referenced in Section 105(1)(d) of the act are administrative in nature, and do not constitute the provision of a transmission service.<sup>1042</sup>

929. AltaLink added that Section 2(1)(b) of the *Distribution Tariff Regulation* mentions the requirement that the charge for system access service be included in the distribution tariff in the context of being a component of “distribution access service.” It argued that the reference to the separate system access service charge in relation to “distribution access service” elements supports the interpretation that a DFO’s duties in relation to system access service are not a transmission service.<sup>1043</sup>

930. AltaLink submitted that Fortis failed to provide support for its assertions that the inclusion of transmission services within the electric distribution services provided by a DFO reflects an intention to allow for harmonization and to impart economic discipline on the DFO when it arranges and financially settles system access service on behalf of its end-use customers.<sup>1044</sup> Moreover, AltaLink asserted that Fortis’s assertion is a self-serving statement and

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<sup>1037</sup> *Electric Utilities Act*, Section 1(1)(1.1)

<sup>1038</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 23.

<sup>1039</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 24.

<sup>1040</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 87.

<sup>1041</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 54.

<sup>1042</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 54-55.

<sup>1043</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 54.

<sup>1044</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 24, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 63.

that Fortis's explanation does not reflect the fact that allowing the DFO to make decisions on connection facilities allows it to build rate base without being exposed to any liability.<sup>1045</sup>

931. AltaLink submitted that its proposal does not affect economic signals to end-use customers because the DFO and the end-use customer will still pay the customer contribution in accordance with the ISO tariff. Shifting the investment from Fortis's shareholder to AltaLink's shareholder does not affect Fortis's ability to respond to price signals. If anything, AltaLink submitted that taking away the opportunity for a pure-play DFO to earn a return on customer contributed amounts improves the economic signal, because it ensures that the pure-play DFO's investment decisions are made on the basis of economics, and not on the basis of shareholder incentives.<sup>1046</sup>

932. AltaLink submitted that Fortis's allegation that AltaLink's contribution proposal will lead to tariff shopping is unfounded, and reflects the fact that Fortis materially misunderstands AltaLink's proposal.<sup>1047</sup> In this regard, AltaLink noted that its response to AML-FAI-2019JAN28-015(b) addressed Fortis's suggestion that AltaLink's contribution proposal effectively prevents the communication of AESO contributions to DFOs and their customers.<sup>1048</sup> In addition, AltaLink submitted that its rebuttal evidence shows that AltaLink's contribution proposal will preserve and enhance price signals to customers.<sup>1049</sup>

### Commission findings

933. The contributions that may arise from the application of the ISO tariff customer contribution policy to transmission connection projects instituted by DFOs is an important price signal.

934. In Decision 2012-362, the Commission reviewed the AESO's policy determination that there should be parity between direct-connect market participants and DFOs in its development of its customer contribution policy. The issue before the Commission in that proceeding was whether DFOs should be exempted from the need to make contributions under the AESO's contribution policy. The Commission, noting that the AESO was not advocating this approach, determined that:

... if DFOs did not pay a contribution, it would be difficult to provide an appropriate price signal to industrial customers to choose between a transmission or distribution connection. The Commission also accepts that, if differential treatment of DFOs and industrial customers under the AESO's contribution policy were to be endorsed, a number of other significant and potentially complicated changes would have to be made to other aspects of the AESO's tariff, including the potential need to create a new rate class applicable to DFOs to maintain cost causation within the point of delivery (POD) charge component of Rate DTS.

73. However, the Commission considers that the most fundamental reason for which the

<sup>1045</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 63-64.

<sup>1046</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 73.

<sup>1047</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 236.

<sup>1048</sup> Exhibit 22942-X0420, PDF pages 32-33.

<sup>1049</sup> Exhibit 22942-X0451, AltaLink rebuttal evidence, paragraphs 7-9, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 236.

concept of providing a DFO waiver must be rejected is that providing a waiver would effectively nullify the option set out in Section 101(2) of the *Electric Utilities Act* of entering into an arrangement with the AESO for the provision of system access service.

935. The applicable legislation reviewed by the Commission and referenced in the above finding is unchanged and the Commission reaffirms its findings in this regard.

936. Having determined that it is necessary that all demand customers, including DFOs, should be able to approach the AESO with their load information and, all else being equal, receive the same answer regarding their connection contribution, the Commission has considered whether it is necessary that the DFO be compensated for its expenditure on contributions through its regulated tariff as is currently done, or whether it is possible for the DFO to be compensated through the means proposed by AltaLink.

937. The Commission has considered the duties of the DFO referenced by Fortis in sections 105(1)(d) and 105(1)(h) of the *Electric Utilities Act* and does not find that these duties prescribe how the DFO, who provides for system access service to its customers, settles the costs for that system access service with the AESO. AltaLink's contribution proposal continues to require the DFO to pay a customer contribution to the TFO as provided for under the current AESO customer contribution policy consistent with these duties.

938. Further, the Commission notes that Section 2(b) of the *Distribution Tariff Regulation* requires that a distribution tariff must include a charge for system access service and clearly provides that this charge is to be separate from charges for "other components of distribution access service." AltaLink's proposal does not prevent the DFO from including a charge to its customers for the provision of system access service, which is what this regulation requires.

939. Considering these provisions, the Commission is satisfied that because AltaLink's proposal maintains the price signal associated with the contribution to the DFO, and does not impede the ability of the DFO to flow through the contribution to its end-use customers, the harmonization goals in respect of the ISO tariff contribution policy that have been adopted by the Commission and its predecessor in prior decisions would not be adversely affected if AltaLink's contribution proposal were to be adopted by the Commission.

#### **8.1.2.5 Does AltaLink's proposal discriminate against "pure-play" DFOs?**

940. Fortis submitted that AltaLink's proposal singles it out because it is the only pure-play DFO and, therefore, the proposal discriminates against market participants solely based on service area.<sup>1050</sup>

941. In its evidence, Fortis stated that the only tariff it is subject to is the ISO tariff and that because the ISO tariff is intended to be open and non-discriminatory, any attempt to circumvent the ISO tariff by instituting a separate rate or rider applied directly to a DFO would almost certainly be counter to legislation.<sup>1051</sup>

942. Fortis submitted that the decision to make the ISO tariff the only tariff to apply charges for system access service reflects an underlying rationale to provide the same treatment to DFOs and to customers who had received an exemption under Section 101(2) of the *Electric Utilities*

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<sup>1050</sup> Exhibit 22942-X0559, Fortis argument, paragraph 13, bullet (d).

<sup>1051</sup> Exhibit 22942-X0559, Fortis argument, paragraph 18.

Act.<sup>1052</sup> Consequently, Fortis submitted that a central flaw of AltaLink's contribution proposal is that it would impart different treatment to Fortis.<sup>1053</sup> As well, Fortis submitted that treating customer contributions differently creates the potential for "seams issues" because AltaLink's contribution proposal would remove contribution as a price signal.<sup>1054</sup>

943. AltaLink responded to Fortis's discrimination issue in its argument. AltaLink noted that in Proceeding 21341,<sup>1055</sup> Fortis initially complained about discrimination on the basis that the contribution proposal was brought forward as part of AltaLink's tariff. AltaLink submitted that insofar as AltaLink's proposal is under consideration in the ISO tariff proceeding and would apply to all DFOs, these concerns have now been addressed.<sup>1056</sup> Consequently, AltaLink submitted that in the current proceeding, Fortis has shifted the focus of its discrimination argument to direct connect customers. AltaLink argued that its contribution proposal does not discriminate based on location and, therefore, it is not contrary to Section 30(3) of the *Electric Utilities Act*.<sup>1057</sup>

944. Fortis also contended that AltaLink's proposal is contrary to the legislation because market participants do not have a reasonable opportunity to exchange electric energy and/or ancillary services as provided in Section 29 of the *Electric Utilities Act* and because the provision would result in a tariff that is "unjustly discriminatory," contrary to Section 121(2)(b) of the act.

945. AltaLink rejected these arguments stating that:

- Different treatment is not discrimination; rates are only discriminatory if they are different for no reason.<sup>1058</sup>
- Where a "reasonable distinction" exists, customers must be treated differently to avoid discrimination.<sup>1059</sup>
- The key difference justifying different treatment is the difference in incentives for DFOs as compared to other market participants.<sup>1060</sup>
- The fact that Fortis would lose the benefit of being able to invest in transmission facilities under AltaLink's proposal does nothing to impede Fortis's ability to obtain system access service for its customers.<sup>1061</sup>

946. In its reply argument, Fortis repeated its position that there is no basis in law to discriminate between a pure-play DFO and a utility with integrated TFO and DFO operations as it pertains to the customer contribution issue.<sup>1062</sup> Fortis submitted that discrimination on the basis of being a pure-play DFO would conflict with the Commission's long-standing commitment to treat all customers in the same light. Moreover, the Commission has acknowledged that DFOs may be in a better position, and face stronger incentives, to manage AESO contribution costs

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<sup>1052</sup> Exhibit 22942-X0424, sections 5 through 5.3

<sup>1053</sup> Exhibit 22942-X0559, Fortis argument, paragraph 18.

<sup>1054</sup> Exhibit 22942-X0559, Fortis argument, paragraph 19.

<sup>1055</sup> Proceeding 21341, Exhibit 21341-X0021, Fortis Alberta motion dated March 9, 2016, with attachment.

<sup>1056</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 198.

<sup>1057</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 201.

<sup>1058</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 204.

<sup>1059</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 204.

<sup>1060</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 206.

<sup>1061</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 207.

<sup>1062</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 25, bullet (a).

under the performance-based regulation (PBR) framework than under the cost of service framework still in place for TFOs.<sup>1063</sup> Given this, Fortis submitted that a utility that can choose between a cost of service framework and the PBR framework, will choose the cost of service framework that AltaLink operates under in order to avoid being subjected to the incentive scheme created by PBR.<sup>1064</sup>

947. In sur-reply, AltaLink addressed Fortis's claim that AltaLink had provided no credible rationale for treating DFOs and industrial customers differently. AltaLink responded that it had raised the following points in argument:

- Where a reasonable distinction between customers exists, customers must be treated differently to avoid discrimination.<sup>1065</sup>
- The basis for different treatment was the incentives that the current regime creates for DFOs as compared to other market participants.
- A key distinction between DFOs and industrials is that DFOs earn a return on contributions under the current policy; industrial customers do not.<sup>1066</sup>

948. Based on the above, AltaLink submitted that the different treatment of contributions it proposes as between DFOs and industrial customers was justified by both the facts and applicable law.<sup>1067</sup>

### Commission findings

949. Under the statutory scheme for electricity regulation in Alberta, the service territories of AltaLink and Fortis overlap. Consequently, any application for system access service by Fortis will ultimately involve a connection using AltaLink transmission facilities. This directly overlapping service territory also means that Fortis is the only market participant affected, as it is the only the DFO that would be requesting new transmission connection facilities or alterations to existing transmission connection facilities within AltaLink's service territory. Given this, it is unavoidable that AltaLink's contribution policy proposal focuses on how the tariff treatment of contributions arising from Fortis connection projects affects AltaLink.

950. Notwithstanding, AltaLink's proposal is not limited in application to Fortis. In this regard, the Commission notes EDTI's support for AltaLink's proposal. Although Fortis dismisses EDTI's support as reflecting a desire to move costs from the PBR framework applicable to EDTI's distribution operations to the cost-of-service framework applied to its transmission operations, the Commission considers the potential that AltaLink's proposal could be applied in the context of an Alberta DFO that shares a common corporate parentage with a TFO indicates that AltaLink's proposal is not discriminatory against "pure-play" DFOs.

951. With respect to Fortis's suggestion that AltaLink's contribution proposal is discriminatory because it would apply to DFOs but not to direct-connect customers who have obtained an exemption pursuant to Section 101(2) of the *Electric Utilities Act*, direct-connect industry customers unlike DFOs, do not have the opportunity to pass through contributions. The

<sup>1063</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 65, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 27.

<sup>1064</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 31.

<sup>1065</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 204-206.

<sup>1066</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 93.

<sup>1067</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 10.

Commission considers that this is a significant difference and that it is not discriminatory to treat customers with fundamentally different circumstances differently, if such different treatment is warranted for other reasons, such as a fundamentally different incentive structure.

952. The Commission has addressed harmonization or “seams” concerns in Section 8.2.3.3 above.

953. Further, to the extent that AltaLink’s proposal could be applied to any DFO in Alberta, and if so applied, would apply to all transmission connection projects located within the DFOs service territory, the Commission disagrees with Fortis’s suggestion that AltaLink’s contribution proposal discriminates on the basis of location, contrary to Section 30(3) of the *Electric Utilities Act*.

#### **8.1.2.6 Utility Asset Disposition decision linkages to AltaLink’s contribution proposal**

954. AltaLink submitted that in Decision 2013-417,<sup>1068</sup> the Utility Asset Disposition decision (UAD Decision), the Commission determined on the basis of the Supreme Court of Canada’s *Stores Block* decision that *Stores Block* had established fundamental principles related to utility asset ownership. These principles included that utility customers do not acquire an ownership interest in utility assets used to provide utility service, and that utility assets that are not “used and required to be used” for utility service must be removed from rate base.<sup>1069</sup>

955. Despite identifying the potential for future risk arising from the application of UAD decision principles, AltaLink submitted that its submissions on conflicts between the AESO’s current contribution policy and the UAD Decision should not be taken as any admission that bears UAD-related liability in relation to future events.<sup>1070</sup>

956. AltaLink submitted that because the UAD Decision was released after the last major review of the AESO’s contribution policy, this decision represents a material development in the consideration of AltaLink’s contribution policy concerns. As such, AltaLink submitted that the UAD Decision informs the contribution policy in relation to the disconnect in the current contribution policy between the risk of asset ownership borne by the TFO, and the return on the capital investment that accrues to the DFO paying the contribution.<sup>1071</sup>

957. AltaLink noted that an extraordinary retirement, causing a removal from rate base, occurs from causes not reasonably assumed to have been anticipated in depreciation or amortization provisions.<sup>1072</sup> In this regard, AltaLink noted that in applying the *Stores Block* principles, the Commission determined that where a utility asset becomes subject to an extraordinary retirement, the asset must be removed from rate base, and any gain or loss accrues to the utility and its shareholders.<sup>1073</sup> AltaLink explained that the UAD Decision identified several events that could trigger extraordinary retirements, including:

- sudden and complete obsolescence;
- abandonment;

<sup>1068</sup> Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.

<sup>1069</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 104.

<sup>1070</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 128.

<sup>1071</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 103.

<sup>1072</sup> Decision 2013-417, paragraph 305, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 107.

<sup>1073</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 105.

- overdevelopment/construction of more facility than required for future needs;
- the use of property for non-utility purpose;
- unusual casualties, including fire, storms, or floods; and
- the unexpected and permanent shutdown of an entire operating assembly or plant.<sup>1074</sup>

958. AltaLink submitted that the UAD Decision reflects the Commission's interpretation of property law in light of the Supreme Court of Canada's (SCC) decision in *Stores Block*. In particular, AltaLink noted that the Commission determined that *Stores Block* established key principles that utility customers do not own utility assets, and that, while utility customers pay for utility assets, utility customers are not entitled to the intrinsic benefits of ownership, nor do they face the intrinsic risks of ownership.<sup>1075</sup>

959. AltaLink submitted that the current treatment of DFO contributions conflicts with the UAD Decision because the current practice causes AltaLink to assume material risks and ownership responsibility over the life of its transmission assets without the corresponding ability to earn a return on a portion of transmission assets contributed by a DFO. Conversely, Fortis does not own contributed transmission assets and has no physical assets on its books,<sup>1076</sup> yet earns a return despite not facing these risks. AltaLink asserted that this disconnect between asset risk and return is contrary to fundamental corporate and property law principles that benefits and risks of ownership should accrue to the owner of the utility asset and this matter must be addressed within the current proceeding.<sup>1077</sup>

960. In addition, AltaLink noted that the current contribution practice does not align with depreciation activities. Specifically, AltaLink explained that it includes transmission facility retirements within its depreciation studies; however, Fortis cannot include transmission assets in its depreciation studies, because it owns none. Consequently, insofar as the rate of consumption of all AltaLink transmission facilities is based on AltaLink studies, Fortis's amortization rate for its AESO contributions reflects the depreciation history of its own distribution assets. This is significant because any determination of an extraordinary retirement would require an examination of AltaLink's retirement history, not Fortis's.<sup>1078</sup>

961. AltaLink submitted that its proposed treatment of contributions would bring the treatment of contributions in alignment with principles set out in the *Stores Block* decision and the UAD Decision.<sup>1079</sup>

962. EDTI submitted that AltaLink's proposal is consistent with the utility asset ownership principles established in *Stores Block*, and as applied by the Commission in the UAD Decision.<sup>1080</sup> EDTI also agreed that the UAD Decision represented a substantial change in circumstances since the Commission's last in-depth review of the AESO's contribution policy and that it highlights the importance for the Commission to ensure that risks and rewards of asset

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<sup>1074</sup> Decision 2013-417, paragraph 327, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 106.

<sup>1075</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 110-112.

<sup>1076</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 114.

<sup>1077</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 113.

<sup>1078</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 114.

<sup>1079</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 125-127.

<sup>1080</sup> Decision 2013-417, paragraph 330, cited at Exhibit 22942-X0550, EDTI argument, paragraph 122, bullet 2.



ownership stay with the relevant utility owner. That is, transmission assets stay with TFOs and distribution assets stay with DFOs.

963. In reply, Fortis disagreed with AltaLink's view that the AESO's current contribution policy is inconsistent with the UAD Decision.<sup>1081</sup>

964. Fortis noted that the UAD Decision states, in part:

... Utility customers, when they pay for utility service, do not acquire a property interest in utility company assets. The utility and its investors, are entitled to the benefits and are subject to the risks intrinsic to property ownership. Accordingly, any gains or losses on utility assets are for the account of the utility and its shareholders, not customers.<sup>1082</sup>

965. Fortis submitted that this passage from the UAD Decision confirms that customer contributions, which constitute a payment for a utility service as contemplated in this finding, do not have any effect on ownership, and that the issues of payment for service and ownership are separate and distinct.<sup>1083</sup>

966. Fortis submitted that to the extent AltaLink may bear any UAD-related risk, the fact that Fortis makes a contribution limits the degree of such risk. Fortis submitted that this is because the quantum of UAD-related risk applies to the utility's rate base, which is limited to the amount that the utility is permitted to invest by the contributions received.<sup>1084</sup>

967. Fortis also disagreed with AltaLink's suggestion in argument that it is not compensated for UAD-related risk. Fortis submitted that such compensation for UAD-related risk can be shown by the fact that in its 2013 generic cost of capital decision (Decision 2191-D01-2015), the Commission found that both the capital market and credit agencies have factored in the effect of the UAD Decision.<sup>1085</sup>

968. Fortis concluded that it agrees with AltaLink that the UAD Decision was a significant development in Alberta's regulatory environment; however, the decision does not justify a change in the customer contribution policy. If anything, Fortis submitted that the risks associated with extraordinary retirements arising from the UAD Decision are reduced under the current contribution policy. This is because any UAD-related risk is limited to the amount of the investment in the asset.<sup>1086</sup>

### Commission findings

969. The Commission agrees with Fortis's position that AltaLink bears UAD-related risk on only the amount of capital invested, net of contributions, and Decision 2191-D01-2015 addressed UAD-related risk.

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<sup>1081</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 113 to 118, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 19.

<sup>1082</sup> Decision 2013-471, paragraph 330.

<sup>1083</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 20.

<sup>1084</sup> Decision 2013-417, paragraph 305, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 21.

<sup>1085</sup> Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015, paragraphs 335-338, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 23.

<sup>1086</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 24.

970. In consideration of the foregoing, the Commission considers that the UAD Decision does not compel the Commission to direct the AESO to adopt AltaLink's contribution proposal.

971. The Commission has addressed depreciation issues in Section 8.1.3.4 below.

#### 8.1.2.7 Guidance from the *Ameren* Decision

972. AltaLink suggested that a recent Federal Energy Regulatory Commission (FERC) order following a US District of Columbia (DC) Court of Appeal decision (the *Ameren* Decision) provides guidance on this issue.

973. The *Ameren* case dealt with FERC orders that had eliminated an option within the Midcontinent Independent System Operator, Inc.'s (MISO) tariff that permitted a TFO to finance network upgrades required by an interconnecting generator. Under the MISO tariff, any interconnecting generator is responsible for 100 per cent of network upgrade costs. However, prior to the FERC order considered by the appellate court, a TFO could choose to finance the network upgrades and then recover the incoming generator's portion of the costs through network upgrade charges that include both a return of, and a return on, capital.

974. The appellate court vacated the FERC orders and returned the matter back to the FERC for redetermination. In its decision, the appellate court determined that the FERC orders "forced [shareholders] to accept incremental exposure to loss with no corresponding benefit."<sup>1087</sup> Further, the court determined that the FERC had forced the TFOs to "accept risk-bearing additions to their network with zero return."<sup>1088</sup>

975. In its reconsideration of the issue, the FERC reversed its position and directed MISO to restore the TFO's ability to unilaterally elect to fund the capital costs of network upgrades.

976. AltaLink submitted that the *Ameren* case is similar to AltaLink's concerns with respect to the current treatment of Fortis contributions. It submitted that the *Ameren* decision reasons reflected principles set out in the *Stores Block*-based UAD Decision, namely, that "the utility and its investors are entitled to the benefits and subject to the risks intrinsic to property ownership."<sup>1089</sup> Further, it submitted that the current treatment of Fortis contributions reflects the following flaws identified in the *Ameren* Decision:

- the current contribution policy exposes AltaLink to all the risks of transmission line ownership without the corresponding return for that exposure; and
- the current contribution policy effectively forces AltaLink to construct and operate DFO funded upgrades on a non-profit basis.<sup>1090</sup>

977. AltaLink suggested that the *Ameren* findings are even stronger when applied to Alberta because the risk considered in *Ameren* was litigation risk whereas, AltaLink faces UAD asset risk that is unique to Alberta.<sup>1091</sup> Further, the FERC regime, unlike Alberta, still accommodates

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<sup>1087</sup> *Ameren* at pages 18, 25

<sup>1088</sup> *Ameren* at page 21.

<sup>1089</sup> Decision 2013-417, paragraph 330.

<sup>1090</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 143.

<sup>1091</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 142.

vertically integrated utilities; therefore, the U.S. commercial financial market is more likely than Alberta to accommodate a proposal like the one struck down in *Ameren*.

978. In reply, Fortis argued that the *Ameren* decision reflected statutory and constitutional principles applicable in the United States of America and, as such, should be given no weight. In its view, the central issue in this case was that transmission owners cannot be forced by the FERC to construct and operate generator-funded network upgrades under the Federal Power Act and the US Constitution.<sup>1092</sup> Given this context, Fortis submitted that the *Ameren* complaint was grounded in principles that are not applicable to the situation in Alberta.<sup>1093</sup>

979. Fortis noted that AltaLink's argument that *Ameren* is applicable to the consideration of the treatment of contributions is based on AltaLink's observation that the U.S. Federal Power Act has "just and reasonable rate" provisions similar to those set out in Section 121 of the *Electric Utilities Act*, and on the basis of AltaLink's assertion that *Ameren* could not survive despite the fact that, unlike Alberta which expressly prohibits DFOs from earning a return on transmission facilities, the U.S. environment tolerates integrated utilities and a broad basis of tariff recovery.

980. In any event, Fortis noted that in the *Stores Block* decision, the SCC included a statement that "American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes ..."<sup>1094</sup>

### Commission findings

981. The Commission does not consider that *Ameren* provides any assistance in its determination of whether to adopt AltaLink's proposed contribution policy. The Commission agrees with the submissions of Fortis in this regard.

#### 8.1.2.8 Retroactivity concern

982. AltaLink's proposal only applies to the unamortized balance at December 31, 2017. Therefore, AltaLink submitted that its contribution proposal does not involve retroactive divestiture.<sup>1095</sup>

983. In argument, AltaLink noted that Fortis's evidence did not raise any issue that AltaLink's contribution proposal could potentially contravene retroactive rate making principles. However, AltaLink noted that in its response to FAI-AUC-2019FEB19-007,<sup>1096</sup> Fortis appeared to suggest a concern referring to "forced retroactive divestiture to TFOs of significant contribution amounts invested by DFOs under previously approved tariffs."

984. AltaLink submitted that Fortis's suggestion of a retroactivity concern in its FAI-AUC-2019FEB19-007 response suggests that Fortis believes it has an entitlement to the continuation of the tariff treatment it has enjoyed to date. However, AltaLink noted that the Supreme Court of Canada has previously ruled that a person has no vested right to the continuation of a specific

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<sup>1092</sup> Exhibit 22942-X0556, Appendix A: *Ameren Services Co. v. FERC*, 800 F.3d 571 (D.C. Cir. 2018), page 25.

<sup>1093</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 32.

<sup>1094</sup> *Stores Block* at paragraph 54, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 34.

<sup>1095</sup> Exhibit 22942-X0342, AltaLink evidence, paragraph 123.

<sup>1096</sup> Exhibit 22942-X0437, PDF page 11.

law, which can be extended to mean that no person has a vested right to the continuation of a specific rate.<sup>1097</sup>

985. In its reply argument, Fortis submitted that because AltaLink's proposal would require a transfer of existing rate base from one entity to another, AltaLink's suggestion that its contribution proposal should apply to unamortized balances constitutes retroactive ratemaking.<sup>1098</sup>

986. In sur-reply, AltaLink submitted that because the Commission regularly orders rate base adjustments through determinations that the undepreciated capital cost of assets are not "used and required to be used," the transfer of existing rate base from one utility to another is not retroactive ratemaking.<sup>1099</sup>

987. AltaLink submitted that the only evidence Fortis provided to support its retroactive rate making argument is a single sentence from an unrelated Fortis IR response<sup>1100</sup> in which Fortis makes a statement questioning the legality of "forced retroactive divestiture" on contribution amounts invested in prior tariffs.

988. AltaLink indicated that it had assumed that Fortis's reference to "forced retroactive divestiture" related to AltaLink's proposal to refund unamortized contribution balances at December 31, 2017 to the AESO (and then to Fortis) in exchange for charging the DFO for the increased TFO cost of service from the transfer.<sup>1101</sup> However, AltaLink considered that because its proposal is restricted to unamortized balances, it is strictly forward looking. Accordingly, since its proposal is strictly prospective, Fortis's characterization of this aspect of its proposal as "forced retroactive divestiture" is factually inaccurate.<sup>1102</sup>

989. AltaLink submitted that retroactive ratemaking:

- "establish[es] rates [for a past period] to replace or be substituted to those which were charged during that period";<sup>1103</sup>
- is characterized by changes to rates that have already been paid;
- is generally prohibited because of the fact that it creates a lack of certainty for utility consumers; and<sup>1104</sup>
- is generally distinguished from "retrospective ratemaking" which imposes shortfalls (or surpluses) incurred by previous generations on current consumers (which is generally prohibited on intergenerational equity grounds).<sup>1105</sup>

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<sup>1097</sup> Exhibit 22942-X0555, AltaLink argument, paragraphs 210-211.

<sup>1098</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 36.

<sup>1099</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 17.

<sup>1100</sup> Exhibit 22942-X0437, FAI-AUC-2019FEB19-007.

<sup>1101</sup> Exhibit 22942-X0342, AltaLink evidence, paragraph 123, cited at Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 20.

<sup>1102</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 21.

<sup>1103</sup> *Bell Canada v. Canada* (Canadian Radio - Television and Telecommunications Commission), [1989] 1 S.C.R. 1722 at 1749, quoted in *Calgary (City) v. Alberta* (Energy and Utilities Board), 2010 ABCA 132 at para. 47.

<sup>1104</sup> AltaLink noted that the circumstances in which retroactive ratemaking will be allowed were discussed in *Re ATCO Pipelines*, 2014 ABCA 28 at paragraphs 56-57.

<sup>1105</sup> Exhibit 22942-X0589, AltaLink sur-reply, paragraph 22.

990. In consideration of these criteria, AltaLink submitted that its contribution proposal should be considered to be neither retroactive nor retrospective. In this regard, AltaLink submitted that its contribution proposal is not retroactive because it does not alter or replace any past rates that have already been paid and it only pertains to unamortized balances and, therefore, its contribution proposal is purely forward-looking (i.e., prospective) in nature. AltaLink also submitted that its contribution proposal is not retrospective because its proposal does not impose a shortfall or surplus on current customers that was incurred by prior customers.<sup>1106</sup>

### Commission findings

991. The Commission notes that a major concern leading to the establishment of principles against retroactive ratemaking is that a utility could be subject to a cost for which the ability to request a corresponding revenue requirement authority has been exhausted. However, the Commission notes that under AltaLink's proposal to apply its proposed contribution policy to any unamortized AESO contribution balance as at December 31, 2017, Fortis will be refunded this amount, leaving Fortis financially whole. Accordingly, the Commission agrees with AltaLink that its proposal does not amount to "forced retroactive divestiture."

992. The Commission also notes that under the capital tracker mechanism for AESO contributions, Fortis has applied ongoing adjustment to AESO contribution amounts to projects that have been ascribed to true-up years that have previously been examined by the Commission.<sup>1107</sup> Further, the Commission notes that the true up of Fortis's AESO contribution amounts to December 31, 2017, is currently under consideration in Proceeding 24681. Based on this, the Commission considers that the gross amount of Fortis's AESO contribution balance as at December 31, 2017, from which any unamortized balance will be determined, has not yet been finalized.

993. Further to the discussion in Section 8.1.3.4 below, the Commission also notes that Fortis's unamortized balance at December 31, 2017, incorporates prior amortization that reflects Fortis's use of an AESO contribution amortization rate based on a much shorter average service life than AltaLink applies to its transmission assets. However, because AltaLink is only proposing to apply its contribution proposal to unamortized balances, AltaLink's proposal makes no attempt to "recover" or "rectify" any harm to ratepayers that may arguably have occurred by Fortis's use of a shorter service life assumption to determine its AESO contribution amortization rate. Accordingly, the Commission considers that AltaLink's proposal is not retroactive or retrospective in respect of AESO contribution amounts that have already been amortized by Fortis and, instead, only applies to the balance that remains.

994. Finally, the Commission agrees with AltaLink that because there is no vested right to the continuation of a specific law, the fact that Fortis will not continue to enjoy a regulated return from unamortized balances as at December 31, 2017, that would be transferred to AltaLink under AltaLink's contribution proposal, would not constitute retroactive rate making.

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<sup>1106</sup> Exhibit 22942-X0589, AltaLink sur-reply, paragraph 23.

<sup>1107</sup> Decision 22741-D01-2018, paragraphs 56-62.

### 8.1.3 Public interest arguments in respect of AltaLink contribution proposal

995. In addition to the legal argument presented, AltaLink and Fortis also raised public interest arguments in their submissions in support of their respective positions. The Commission's consideration of these issues is provided under separate subheadings below.

#### 8.1.3.1 Comparative size of Fortis's AESO contribution balance

996. Fortis noted in its evidence that it arranges system access service for more than 550,000 sites, serving customers at 253 PODs out of approximately 550 total PODs located in Alberta. Fortis added that through the *Roles, Responsibilities and Relationships Regulation*, it is responsible to arrange for system access service for the smaller rural electrification associations (REAs) and municipally owned DFOs that operate downstream of Fortis's distribution system.<sup>1108</sup>

997. Fortis explained in its evidence that the main reason its AESO contribution balances appear to be high compared to other DFOs is because it arranges more system access service than other DFOs. In this regard, it noted that it serves a total population of more than 900,000 people that includes seven of 10 of Canada's fastest growing cities and that its service territory does not give it the benefit of serving a large population located in a concentrated geographic area.<sup>1109</sup>

998. AltaLink submitted that Fortis's evidence emphasizing the size of its service area and rate of population growth does not explain why its customer contribution levels are so much higher than other DFOs, or why its AESO contributions make up such a higher proportion of its overall capital spending when compared to other DFOs.<sup>1110</sup>

999. AltaLink submitted that it provided compelling evidence that:

- Fortis's contributions are much higher than other DFOs and have grown substantially between 2012 and 2017.<sup>1111</sup>
- Fortis's contributions for transmission projects significantly exceed AESO investment in respect of its projects.<sup>1112</sup>
- Transmission contributions represent a larger percentage of Fortis's rate base than other DFOs as evidenced by the fact that transmission contributions represented 13 per cent of Fortis's 2018 rate base and only four per cent of ATCO Electric distribution's 2018 rate base.<sup>1113</sup>
- AltaLink noted that Fortis's contributions in its rate base grew from \$9 million in 2006 and are projected to reach \$553 million in 2022.

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<sup>1108</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 4.

<sup>1109</sup> Exhibit 22942-X0424, Fortis evidence, paragraphs 5-6.

<sup>1110</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 86.

<sup>1111</sup> Exhibit 22942-X0342, AltaLink evidence, paragraph 79, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 83.

<sup>1112</sup> Illustrated by figure in Exhibit 22942-X0555, AltaLink argument after paragraph 82.

<sup>1113</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 84.

1000. AltaLink noted that while Commission counsel questions suggested that Fortis's relatively higher contributions could be explained by Fortis's DTS contracting practices, Mr. Senko confirmed in a letter that Fortis's contributions reflected reliability-driven projects.<sup>1114</sup>

1001. In addition, AltaLink submitted that in a response to Mr. Senko's submission in direct oral evidence, Fortis confirmed this interpretation by noting that Fortis does not consider that its DTS contracting practices differ materially from other DFOs, and that while Fortis has generally prioritized capacity over reliability when considering transmission projects, reliability projects driven by need have outstripped capacity projects over the last few years.<sup>1115</sup>

1002. In reply, Fortis noted that while AltaLink notes that Fortis's AESO contributions are higher than other DFOs, and suggests that the comparative size of Fortis's AESO contributions is related to the fact that Fortis applies its own reliability standards without AESO oversight,<sup>1116</sup> or "perverse incentives,"<sup>1117</sup> it rejected any AltaLink suggestions that Fortis pursues projects giving rise to AESO contribution projects for reasons other than reliability and good utility practice.<sup>1118</sup> It added that AltaLink's counsel did not examine Fortis's witnesses with respect to either the comparison of the size of contributions relative to other DFOs or in respect to Fortis's reliability standards, and how Fortis applies them.<sup>1119</sup>

### **Commission findings**

1003. AltaLink argues that its contribution proposal is in the public interest because it will neutralize Fortis's incentive to pursue unnecessary reliability projects that earn a regulated return on AESO contributions.

1004. The Commission notes that AltaLink illustrates the difference between Fortis and other Alberta DFOs in Figure 1-3 from its argument, reproduced below:

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<sup>1114</sup> Transcript Volume 3, pages 591-592; Transcript Volume 5, page 857

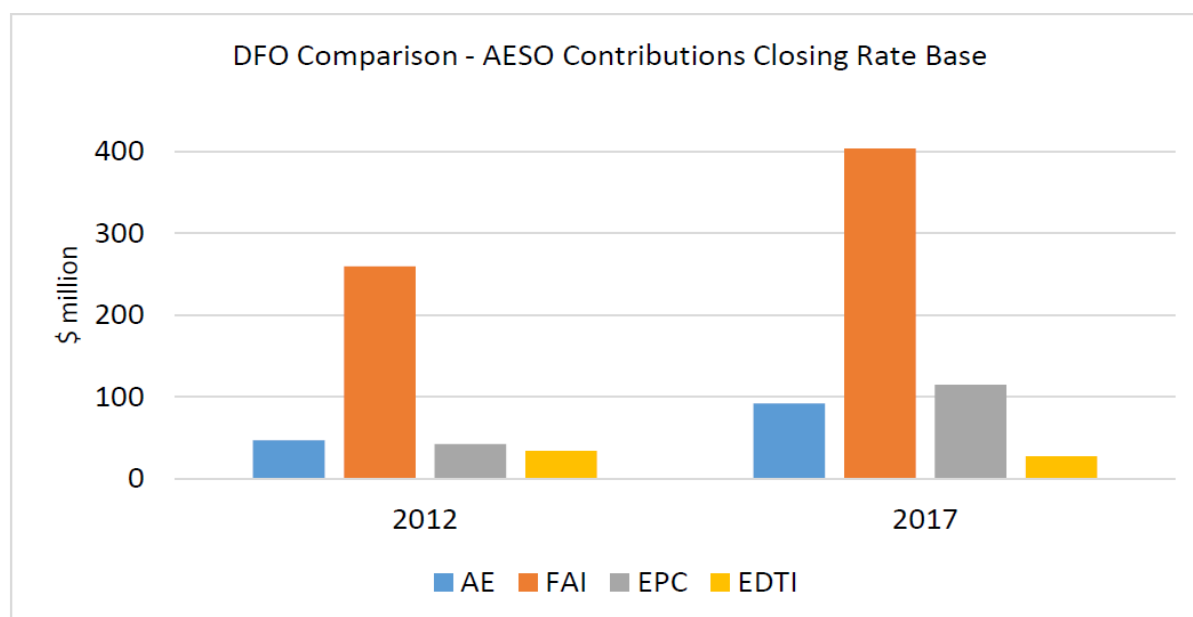
<sup>1115</sup> Transcript Volume 6, page 1077, line 9 – page 1078, line 12.

<sup>1116</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 10.

<sup>1117</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 153.

<sup>1118</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 7.

<sup>1119</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 7(b).

**Figure 3. Comparison of AESO contributions closing rate base between DFOs**

Source: Exhibit 22942-X0555, AltaLink argument, Figure 1-3, PDF page 28.

1005. The evidence supports AltaLink's contention that Fortis's AESO contribution amounts are significantly higher than those of other distribution utilities.

1006. Characteristics specific to Fortis such as its geographical service territory, large population served, comparatively high economic growth rates of the communities it serves, and the absence of advantages such as geographic concentration, provide some explanation for the differential in AESO contribution amounts as compared to other distribution utilities. However, considering the size of the difference between Fortis and other distribution utilities, the Commission is not persuaded by Fortis that these factors are sufficiently different when compared to other distribution utilities, to account completely for the difference in contribution amounts. It is noteworthy that both ATCO Electric and Fortis serve customers in rural areas; yet, as AltaLink has indicated in its evidence, transmission contributions represented 13 per cent of Fortis's 2018 rate base and only four per cent of ATCO Electric Distribution's 2018 rate base.

1007. Commission counsel questioned Fortis and AltaLink as to whether the difference in AESO contribution levels amongst Fortis and the other major DFOs, could be caused in part, by differences amongst Fortis's DTS contracting practices and those of other DFOs. Both AltaLink<sup>1120</sup> and Fortis<sup>1121</sup> submitted that DTS contracting differences should not be considered a significant driver of the differences.

1008. Fortis was particularly adamant:

29. FortisAlberta notes that the Company's contracting practices formed the subject of considerable discussion over the course of the oral hearing. There appears to be a misapprehension on the part of some parties that FortisAlberta, as a DFO market participant, contracts for minimum DTS capacity, thus minimizing transmission

<sup>1120</sup> Exhibit 22942-X0517.

<sup>1121</sup> Exhibit 22942-X0559, Fortis argument, paragraphs 29-30.



investment and maximizing its required contribution, while other DFO's maximize their DTS contract levels, to minimize the resultant contribution.

30. This is simply not the case. In the context of the AESO's proposed Section 5.2(2), FortisAlberta's response to an information request from Access Pipeline Inc. and the ATCO Electric evidence show that there is no material difference in contracting practices between ATCO Electric and FortisAlberta. One needs to look no further than the DTS tariff and the investment levels and price signals contained therein to determine how a rational market participant, DFO or not, is incented to select a DTS contract level to minimize transmission costs for the customer, or in this case for its DFO customers. Contracting for maximum capacity would attract significantly more transmission tariff costs if other DFOs do not do the same, as the monthly DTS billing capacity costs associated with a higher contract capacity, outweighs any incremental AESO contribution costs that may be incurred as a result of not contracting at a higher DTS level.<sup>1122</sup> [footnotes omitted]

1009. Most of the other DFOs did not provide submissions on their own DTS contracting practices in this proceeding.<sup>1123</sup> However, considering the consensus between AltaLink and Fortis regarding DTS contracting practices as a driver for the large differences in AESO contributions, the Commission is prepared to accept Fortis's assertion that DTS contracting practice differences do not explain the differences in AESO contribution levels amongst Fortis and the other major distribution utilities.

1010. The Commission has addressed AltaLink's proposition that incentives arising from the current treatment of Fortis's contributions may be a contributing factor to explain the significant difference in the AESO contribution balances amongst Fortis and other DFOs that cannot be attributed to the Fortis's service territory and customer base in Section 8.1.3.2 below.

### **8.1.3.2 AESO oversight and the incentive to overbuild**

1011. AltaLink noted that price signals provide incentives that affect both the allocation of resources and behaviour<sup>1124</sup> and submitted that the AESO's current contribution policy sends proper price signals to non-regulated market participants because their shareholders must recover any costs in excess of the AESO investment allowance from their shareholders.<sup>1125</sup> However, a pure-play DFO like Fortis is able to recover costs related to customer contributions from their customers and earn a return on the amount. Consequently, AltaLink argued that a pure-play DFO has an incentive to invest in projects.<sup>1126</sup>

1012. AltaLink submitted that these incentives are exacerbated by the fact that the need for reliability projects is determined by the DFO, without effective oversight by the AESO. In this regard, AltaLink noted the AESO's testimony that distribution planning is beyond the AESO's

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<sup>1122</sup> Exhibit 22942-X0559, Fortis argument, paragraphs 29-30.

<sup>1123</sup> ATCO discussed DTS contracting capacity in its evidence (Exhibit 22942-X0333) at PDF page 13, in support of ATCO's position regarding the AESO's discretion to adjust DTS contract capacity under section 5.2(2) of the proposed 2018 ISO tariff. The Commission does not consider that ATCO's submission on this issue provides substantial information on whether ATCO's approach to setting DTS contract levels for transmission connection projects is comparable to the approach of Fortis to the determination of DTS contract levels.

<sup>1124</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 146.

<sup>1125</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 147.

<sup>1126</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 148.

mandate,<sup>1127</sup> and that the AESO relies primarily on the DFO's assessment of the need for transmission facilities.<sup>1128</sup>

1013. AltaLink submitted that the consequences of the AESO's lack of oversight are apparent given that Fortis's contributions exceeded the AESO's contributions by a large margin over 2012 to 2017,<sup>1129</sup> and by the fact that Fortis's contributions are significantly higher, both in absolute terms, and in terms of percentage of rate base, as compared to any other Alberta DFO.<sup>1130</sup>

1014. AltaLink submitted that the differences amongst Fortis and other DFO contributions is a product of the perverse incentive scheme is supported by the fact that:

- Fortis provided no evidence to explain the discrepancy.
- Fortis failed to demonstrate that the size of its service territory and population growth accounted for the discrepancy.<sup>1131</sup>
- Fortis repudiated the suggestion of Commission counsel that the discrepancy could be explained by differences in contracting practices.<sup>1132</sup>

1015. AltaLink noted that a clarification of the testimony of its witness panel<sup>1133</sup> provided analysis showing that at end of 2017, \$135 million out of \$400 million of Fortis's AESO contributions were driven purely, or primarily, by reliability, and that by the end of 2020, \$210 million of Fortis's AESO contributions will be driven primarily by reliability.

1016. In addition, AltaLink submitted that evidence arising from the Provost hearing shows that over the past five years, 80 per cent of Fortis's approximately six to eight projects per year were driven by reliability. It added that since approximately \$75 million of Fortis's projects were 100 per cent reliability projects in the 2018 to 2020 period alone, this trend appears to be continuing<sup>1134</sup> and that Fortis has produced no evidence to the contrary. Therefore, it is undisputed that the component of Fortis's base K-bar related to customer contributions is projected to grow at a rate of between \$53 million and \$59 million per year between 2018 and 2022.<sup>1135</sup>

1017. AltaLink argued that the Commission should have regard to findings made by the majority and in the dissents prepared by Commission Vice-Chair Michaud in Decision 23339-

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<sup>1127</sup> Transcript, Volume 3, pages 603-605, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 150.

<sup>1128</sup> Transcript, Volume 3, page 608, lines 4-6, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 150.

<sup>1129</sup> Exhibit 22942-X0342, AltaLink evidence, paragraphs 76-78.

<sup>1130</sup> Exhibit 22942-X0342, AltaLink evidence, paragraphs 79-84, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 151.

<sup>1131</sup> Exhibit 22942-X0451, AltaLink rebuttal evidence, paragraphs 25-32.

<sup>1132</sup> Transcript, Volume 3, pages 591-592 and Transcript, Volume 6, page 1077, lines 20-22.

<sup>1133</sup> Exhibit 22942-X0517.

<sup>1134</sup> Exhibit 22942-X0517, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 155.

<sup>1135</sup> At paragraph 156 of its argument (Exhibit 22942-X0555), AltaLink cited the following in footnote 172: Exhibit 22942-X0342, AltaLink Evidence at paragraph 78 and Figure 1-2; Exhibit 22942-X0435, FAI-AML2019FEB19-008(f). AltaLink provided the following additional comment in footnote 172: "Per footnote 63 of AltaLink's Evidence, the forecast data cited by AltaLink were obtained from Fortis' 2017 capital tracker true-up application (Proceeding 23649) and its 2019 annual rate adjustment filing (Proceeding 23893). Fortis did not challenge AltaLink's use of these data in this Proceeding."

D01-2019 (Provost Reliability upgrade project) and in Decision 23393-D01-2019<sup>1136</sup> (Fincastle 336S substation upgrade project) when considering Fortis's incentives in respect of AESO contributions.

1018. AltaLink stated that the key elements of the findings of the majority in Decision 23339-D01-2019 and Decision 23393-D01-2019 were as follows:

- Fortis has the right to address need based on its own system planning criteria.
- Distribution planning is within the DFO's expertise, not the AESO's.
- Evidence of collaboration between the AESO and Fortis in the need assessment satisfies the AESO's public interest mandate.<sup>1137</sup>

1019. AltaLink submitted that conversely, Vice-Chair Michaud's dissent found that the AESO's interpretation of its statutory duties as articulated in both the Provost and Fincastle proceedings, does not provide adequate examination of whether the applied-for project is in the public interest.<sup>1138</sup> In addition, Vice-Chair Michaud:

- disagreed that the AESO is precluded from independently scrutinizing underlying need in response to a DFO SASR driven by the DFO's reliability criteria,<sup>1139</sup> and
- disagreed with the view that the AESO is precluded from independently scrutinizing a SASR submitted by the DFO, driven by the DFO's reliability criteria.<sup>1140</sup>

1020. AltaLink submitted that the view of Vice-Chair Michaud relates to key legislative interpretations regarding the AESO's duty to oversee the SASRs of DFOs. Specifically, Section 34(1)(c) of the *Electric Utilities Act* defines the AESO's obligation to prepare NID applications in response to SASRs. AltaLink explained that the AESO's view is that because of its mandate under sections 17 and 29 of the *Electric Utilities Act*, the AESO is required to accept the SASR itself as defining the need for a project. AltaLink submitted that this position is consistent with the AESO's positions expressed in the current proceeding that:

- Distribution planning standards are DFO documents beyond the mandate of the AESO.<sup>1141</sup>
- The AESO is primarily relying on the DFO's assessment of the need for transmission facilities.<sup>1142</sup>

1021. AltaLink noted that these interpretations of the AESO are not consistent with views set out in the dissents of Vice-Chair Michaud, who set out views that:

<sup>1136</sup> Decision 23393-D01-2019: Fincastle 336S Substation Upgrade, Alberta Electric System Operator, Needs Identification Document Application, Application 23393-A001; AltaLink Management Ltd., Facility Application, Application 23393-A002, Proceeding 23393, February 14, 2019.

<sup>1137</sup> Decision 23339-D01-2019 at paragraphs 143-154; Decision 23393-D01-2019 at paragraphs 112-121, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 157.

<sup>1138</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 158.

<sup>1139</sup> Decision 23339-D01-2019 at paragraphs 284-314; Decision 23393-D01-2019 at paragraphs 146-161, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 158.

<sup>1140</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 158.

<sup>1141</sup> Transcript Volume 3, page 603, lines 19-20, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 160.

<sup>1142</sup> Transcript Volume 3, page 608, lines 4-6, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 160.

- Section 29 of the *Electric Utilities Act* does not mean that the AESO must provide system access service to every market participant at any cost. Instead, the “reasonable opportunity” language allows the AESO to scrutinize need.<sup>1143</sup>
- The requirement in Section 34 of the *Electric Utilities Act* for the AESO to submit a Needs Identification Document also requires that the AESO conduct an independent assessment.<sup>1144</sup>

1022. AltaLink submitted that the majority opinion in the Provost and Fincastle decisions should be reassessed in light of evidence brought forward in the current ISO tariff proceeding that there is little collaboration between the AESO and the DFO on SASRs. In this regard, AltaLink took note of evidence in the current proceeding that the AESO relies on the DFO for its need assessment and that the current contribution policy provides a means for DFOs to invest and earn a return on the very projects for which they strongly influence the initial determination of need.<sup>1145</sup>

1023. AltaLink submitted that the AESO’s testimony in the current proceeding that it is “primarily relying” on the DFO’s assessment of the need for transmission facilities is contrary to AltaLink’s view that the decision as to whether or not transmission or distribution lines are required should be in the hands of an independent party with no financial interest in the outcome. In contrast, AltaLink submitted that because a DFO, unlike the AESO, is motivated by profit, and because the current AESO contribution policy allows the DFO to earn a return on the very facilities for which it has determined the need, the current framework short-circuits the protections offered by an independent ISO.

1024. AltaLink submitted that the concerns regarding the AESO’s oversight expressed in the dissents by Vice-Chair Michaud must be considered in light of the fact that the majority in the Provost and Fincastle decisions did not deny that the AESO’s current contribution policy may provide incentives for the DFO to overspend. Instead, AltaLink noted that it was central to the majority view in both decisions that that DFO’s incentive to “undertake unnecessary capital investments to increase their rate base and returns” were, in theory, “mitigated” or “reduced” by the incentives provided to DFOs under PBR.<sup>1146</sup> However, AltaLink considers that there is no evidence that PBR causes Fortis to limit its expenditures, since AltaLink noted that Fortis’s position is that statutory duties and reliability requirements, and not PBR, determine its investments.<sup>1147</sup>

1025. In its argument, EDTI submitted that the Commission has previously determined that sending proper price signals should be a primary objective of the AESO’s contribution policy.<sup>1148</sup> EDTI submitted that the requirement for a contribution continues to serve as an appropriate and effective price signal to the DFO under AltaLink’s proposal. In addition, EDTI submitted that the

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<sup>1143</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 161.

<sup>1144</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 162.

<sup>1145</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 163.

<sup>1146</sup> In footnote 183 of its argument, AltaLink cites Decision 23339-D01-2019 at paragraph 150-151 and Decision 23393-D01-2019 at paragraphs 118-119. In the same footnote, AltaLink states: “In both cases, the majority also indicated that the impact of PBR “may be part of the Commission’s review of AESO tariff contribution policy provisions in a future AESO tariff proceeding” (Provost decision at paragraph 150; Fincastle decision at paragraph 118).

<sup>1147</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 165.

<sup>1148</sup> Exhibit 22942-X0451, AltaLink rebuttal evidence, paragraphs 7-10; Exhibit 22942-X0414, AML-AUC-2019JAN28-004.

transfer of investment, and return thereon, from the DFO to the TFO removes incentives under which a pure-play DFO can financially benefit from construction of transmission facilities.<sup>1149</sup> In light of this, EDTI submitted that AltaLink's contribution proposal is in the public interest, and should be adopted.<sup>1150</sup>

1026. In reply, Fortis noted that the Fincastle and Provost projects were both approved by the Commission.<sup>1151</sup> In addition, Fortis noted that AltaLink's own evidence confirms that Fortis makes its own assessment of NID prior to submitting a SASR to the AESO, and that a collaborative approach is taken to identifying the most cost-effective technical solution.<sup>1152</sup>

1027. Fortis noted that AltaLink's comments on the Provost and Fincastle decisions focus on the Michaud dissent rather than the majority opinion. However, the Michaud dissent is not relevant because the focus of the Michaud dissent was the lack of analysis by the AESO, not the merits of Fortis's solutions for each project.

### **Commission findings**

1028. As set out in Section 8.1.3.1 above, the size of Fortis's AESO contribution balances in relation to the AESO contribution balances of other DFOs cannot be attributed entirely to differences in the size or nature of Fortis's operations. Further, the Commission found that differences in DTS contracting practices are also not a contributing factor.

1029. Assuming that the current customer contribution policy provides Fortis with a systematic incentive to "overbuild" transmission connection facilities, resulting in aggregate in AESO contribution balances that AltaLink considers to be excessive, this would also imply that excessive facilities were constructed. Further, if facilities in excess of requirements are requested by the DFO, this should result in a determination by the AESO that facilities are in excess of good electric industry practice (GEIP).

1030. As further discussed in Section 8.3, there is little evidence that determinations of facilities in excess of GEIP have been made in respect of specific projects. In particular, the evidence in this proceeding is that unless a determination has been made that the requirement to address a system access service request could be met by distribution voltage connection facilities, no determination has ever been made by the AESO that the requested transmission facilities are unnecessary or excessive. Given this, and given that the evidence on the record of the current proceeding indicates that TFOs like AltaLink were expected to be involved in making such assessments, the Commission finds that there is insufficient evidence to support AltaLink's contention that Fortis has systematically caused the construction of excessive transmission voltage connected facilities.

1031. Accordingly, it follows that there is insufficient evidence to find that the adoption of AltaLink's contribution proposal is necessary to address this issue.

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<sup>1149</sup> Exhibit 22942-X0550, EDTI argument, paragraph 122, bullet 4.

<sup>1150</sup> Exhibit 22942-X0550, EDTI argument, paragraph 122.

<sup>1151</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 7(d).

<sup>1152</sup> Exhibit 22942-X0420 at PDF 18, AML-FAI-2019JAN28-007, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 7(c).

1032. The Commission also takes note of the testimony of Fortis:

We agree with AltaLink's assessment regarding the manner in which reliability-driven projects contribute to the overall AESO contribution amounts insofar as this work does not result in increases to existing DTS contract levels.

However, there are other aspects of this information that require clarification.

Specifically, we have no reason to believe that our DTS contracting practices differ from those of other Alberta DFOs in any significant way. We do not believe that our reliability-driven work can be forecast in the way suggested by AltaLink such that any meaningful 2018 to 2022 trend can be established.

And, to clarify, we prioritize our projects first based on capacity and then on reliability levels. Over the past few years, reliability projects driven by need have simply outpaced our capacity projects. TFO reliability projects that are deemed by the AESO to be participant are largely zero or minimal megawatt projects. Consequently, they attract limited AESO investment, which in turn necessitates increased contributions.<sup>1153</sup>

1033. To the extent that Fortis prioritizes its projects first based on capacity and then on reliability levels, it is reasonable for the Commission to conclude that Fortis is not motivated to advance these facilities in order to earn a return on the customer contribution portion. Consequently, Fortis should be indifferent about AltaLink's proposal because the proposal keeps Fortis financially whole with respect to the payment and refund of contributions.

### **8.1.3.3 Effect of the PBR framework on the need for a contribution policy change**

1034. In its evidence, Fortis submitted that based on Section 10 of Decision 2012-362 under the section titled "Linkages to distribution performance-based regulation," it is apparent that when that decision was released in late 2012, the Commission was already considering how changes to the AESO's contribution policies may have linkages to the PBR framework approved for DFOs. Fortis submitted that in denying the AESO's proposal to allow for more TFO investment, the Commission recognized that DFOs may be in a better position, and have strong incentives, to manage AESO contribution costs under the newly established PBR framework as compared to the traditional cost of service model still in place for TFOs,<sup>1154</sup> as reflected in the following passage from Decision 2012-362:

As discussed in Section 6 above, capital investments needed by DFOs to serve new customers or load growth may not exclusively be provided through distribution voltage facilities. It is possible that some tradeoffs may be made in the design of new or expanded connection facilities such that transmission voltage facilities may be substituted for distribution voltage facilities when assessing alternatives for accommodating load growth. Given this substitutability, and given that the recovery of capital expenditures necessary to safely and reliably accommodate load growth is capped under the PBR formulas, the Commission considers that there may be some inherent incentive for DFOs operating under the PBR regime to potentially adjust facility design under PBR versus what would have been expected under the cost of service regulatory model.<sup>1155</sup>

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<sup>1153</sup> Transcript, Volume 6, pages 1077-1078.

<sup>1154</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 65.

<sup>1155</sup> Decision 2012-362, paragraph 204, cited at Exhibit 22942-X0424, Fortis evidence, paragraph 65.

1035. Fortis provided an overview of the effect of the incentives for capital management under PBR in Section 7 of its evidence. In that section, Fortis noted that:

- The Commission adopted the PBR approach in Decision 2012-237 to address concerns with the incentives operating on utilities under cost of service regulation.<sup>1156</sup>
- The Commission's first generation PBR plans were altered subsequent to the release of Decision 2012-237 to incorporate the "capital tracker" incremental capital funding mechanism.<sup>1157</sup>
- The Commission's second generation PBR plan includes a new incremental capital funding mechanism known as "type 2" or "K-Bar," which the Commission expects will provide the majority of incremental capital funding requirements for PBR regulated utilities.<sup>1158</sup>

1036. Fortis submitted that the adoption of the K-Bar mechanism has the effect that, once established, any distinction that existed between categories of costs is eliminated in the creation of an aggregate incremental capital funding amount. Fortis stated that "[t]he provision of incremental capital funding under K-Bar is premised on the establishment of a base level of capital funding premised on a notional rate base with a provision for incremental annual funding for a prescribed level of capital additions based on historical investment." It further added that "[t]he PBR utility is required to meet all its incremental capital requirements, regardless of driver, using the available funding from the aggregate allowance."<sup>1159</sup>

1037. Fortis claimed that the practical result of the K-Bar funding mechanism is that neither Fortis, nor any other DFO, has an incentive to spend to budget with respect to AESO contributions. Instead, capital funding under PBR provides an incentive to DFOs to manage costs and pursue efficiencies by relying on the additional flexibility provided in the planning and allocation of capital funding. As a result, it is challenged to manage its costs across all of its capital programs to meet its obligations to customers and provide safe and reliable service.<sup>1160</sup> As such, utilities that are subject to PBR are not simply able to recover "any costs related to customer contributions from their rate payers and earn a return on those amounts," as AltaLink has suggested.<sup>1161</sup>

1038. Fortis noted that in 23505-D01-2018, the Commission adopted a Fortis proposal known as the "Hybrid Deferral Account Proposal" to accommodate AESO contribution adjustments arising from changes in previously established DTS contract levels. Fortis submitted that with the adoption of the hybrid approach, Fortis's AESO contributions arising from new investments are fully subject to the incentives in K-Bar, while providing a level of certainty with respect to historical AESO contribution amounts.<sup>1162</sup> Fortis noted that on January 31, 2019, it filed an

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<sup>1156</sup> Exhibit 22942-X0424, paragraphs 106-107.

<sup>1157</sup> Exhibit 22942-X0424, paragraph 108.

<sup>1158</sup> Exhibit 22942-X0424, paragraph 109.

<sup>1159</sup> Exhibit 22942-X0424, paragraph 110.

<sup>1160</sup> Exhibit 22942-X0424, paragraph 111.

<sup>1161</sup> Exhibit 22942-X0342, AltaLink evidence, paragraph 76, cited at Exhibit 22942-X0424, Fortis evidence, paragraph 117.

<sup>1162</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 114.

application for Commission approval of trued-up 2016 and 2017 AESO Contribution amounts for inclusion in base K-Bar.<sup>1163</sup>

1039. EDTI argued that although Fortis's evidence suggests that the current PBR plan requires DFOs to manage their costs carefully over the applicable five-year PBR term, the incentives inherent in the K-Bar mechanism of the Commission's second generation PBR plan must be understood in their full context.<sup>1164</sup>

1040. EDTI submitted that Fortis is correct to point out that under the second generation PBR mechanism, a DFO must manage capital within the funding provided by the I-X formula and K-Bar. EDTI submitted that Fortis is also correct that a DFO will have an incentive to minimize their operating and capital costs to maximize their returns.<sup>1165</sup> However, AltaLink's evidence shows that Fortis has capital funding for AESO contributions of more than \$50 million annually<sup>1166</sup> during the second generation PBR term and it is important to understand that factors other than those described by Fortis may affect incentives.<sup>1167</sup>

1041. In this regard, EDTI submitted that a pure-play DFO would have a financial incentive to minimize its contributions during the second generation PBR term and keep the difference for shareholders; however, it would also be incented to continue to spend to its capital funding in order to continue to be able to maintain its capital funding at a high level going into the next term of PBR.<sup>1168</sup>

1042. EDTI submitted that the incentive to maintain relatively high spending on AESO contributions in spite of the basic incentives of the second generation PBR regime is strong because AESO contributions are a long-term asset and because a pure-play DFO continues to bear none of the risks associated with the AESO contribution asset. Accordingly, EDTI submitted that it would be inaccurate to simplistically conclude that the incentives inherent in the K-Bar mechanism under the second generation PBR regime will negate any financial incentive that a pure play DFO would ordinarily have under the AESO's current contribution policy.<sup>1169</sup>

1043. In reply, while agreeing with EDTI that it has an incentive, in theory, to minimize contributions during the second generation PBR period, Fortis submitted that because of its statutory obligation to serve, the fact that it is financially incented under second generation PBR to manage its capital within the rate revenue limits of the second generation regime will not determine Fortis's expenditure decisions. Rather, because it is subject to a statutory obligation to serve, the rate revenue limits of the second generation PBR regime will not determine what it spends.<sup>1170</sup>

1044. Fortis also responded to EDTI's contention that "the pure play DFO would also be financially incented to continue to spend that capital funding on transmission customer contributions to maximize the probability that it will be allowed to continue to recover this level

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<sup>1163</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 115.

<sup>1164</sup> Exhibit 22942-X0550, EDTI argument, paragraph 123.

<sup>1165</sup> Exhibit 22942-X0550, EDTI argument, paragraph 124.

<sup>1166</sup> Exhibit 22942-X0342, AltaLink evidence, Figure 1-2, and 22942-X0344, AltaLink evidence, Appendix B, cited at Exhibit 22942-X0550, EDTI argument, paragraph 124.

<sup>1167</sup> Exhibit 22942-X0550, EDTI argument, paragraph 124.

<sup>1168</sup> Exhibit 22942-X0550, EDTI argument, paragraph 124.

<sup>1169</sup> Exhibit 22942-X0550, EDTI argument, paragraph 124.

<sup>1170</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 29.



of capital funding through its PBR rates in PBR3,”<sup>1171</sup> arguing that EDTI’s assertion ignores the practical reality that Fortis projects arise due to capacity or reliability needs that must be met to serve its customers. Moreover, because no parties have advance knowledge of how the PBR ratemaking environment will be developed or rebased after the current PBR term, EDTI’s argument is highly speculative.<sup>1172</sup>

### Commission findings

1045. Fortis asserted that its decisions to construct transmission voltage connection facilities are made to fulfill its reliability service obligations and not as a result of PBR incentives. EDTI presented an opposing view on the effect of PBR on the incentive scheme operating on Fortis. Regardless, the Commission will not consider the relative merits of these two positions because it finds that the issues of depreciation and amortization rates and potential ratepayer benefits discussed in sections 8.1.3.4 and 8.1.3.5 are sufficiently determinative of whether to adopt or reject AltaLink’s contribution proposal.

#### 8.1.3.4 Depreciation and amortization rates

1046. Fortis included an analysis in its evidence to show that, overall, ratepayers would be better off financially by maintaining contributions within Fortis’s tariff. As part of its assumptions for the analysis, Fortis noted that there is an 11.5 year difference between the amortization rate that Fortis applies to contributions and the average service life that AltaLink uses for assets constructed for the underlying connection projects giving rise to the contribution.<sup>1173</sup>

1047. During the oral hearing, Ms. Sullivan, on behalf of Fortis, explained that the 11.5 year difference reflects the fact that Fortis amortizes contributions at a rate reflecting the average service life of Fortis’s distribution assets.<sup>1174</sup>

1048. AltaLink argued that the AESO’s current contribution practice under which a DFO can capitalize and earn a return on investment on transmission assets results in a depreciation rate that is not reflective of actual consumption of the transmission assets.<sup>1175</sup> It claimed that Fortis’s use of a shorter service life for amortizing contributions reflects the fact that Fortis treats contributions paid as a “financial asset,” amortizes this asset at a rate consistent with its distribution assets, and then bills its customers based on this amortization.<sup>1176</sup> That is, the 11.5 year difference in the rate of consumption between Fortis and AltaLink reflects the fact that distribution assets are consumed faster than transmission assets.<sup>1177</sup>

1049. AltaLink stated that the Commission has consistently held that depreciation rates should match to the underlying service lives of assets yet the AESO’s current contribution practice has the effect of disconnecting depreciation rates and asset consumption, contrary to both the

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<sup>1171</sup> Exhibit 22942-X0550, EDTI argument, paragraph 124, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 29.

<sup>1172</sup> Exhibit 22942-X0579, Fortis reply argument, paragraph 30.

<sup>1173</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 129.

<sup>1174</sup> Transcript Volume 6, pages 1097-1098.

<sup>1175</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 173.

<sup>1176</sup> Transcript Volume 6, pages 1097-1098, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 174.

<sup>1177</sup> Exhibit 22942-X0424, Fortis evidence at paragraph 129; Transcript Volume 6, pages 1097 and 1098, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 175.

matching principle and the concept of intergenerational equity.<sup>1178</sup> Further, the Commission has repeatedly found that depreciation must reflect actual consumption as assessed through mass property accounts, as reflected in the following Commission findings from the UAD Decision:

Depreciation is the method by which the Commission determines the component of rates intended to compensate the utility for the cost of the assets acquired by the utility for the purpose of providing utility service. The underlying premise of depreciation is to return to the utility the cost of these assets over the period of time that they are used to provide utility service. The positive or negative amounts arising from the retirement and net salvage activities associated with the removal of utility assets from service are also estimated and included within the total depreciation charge as a salvage component.<sup>1179</sup> [Emphasis added by AltaLink]

1050. AltaLink asserted that the fact that the Commission has adopted rate making tools like average service lives and IOWA curves also supports the notion that depreciation service lives should match the predicted rate of consumption.<sup>1180</sup>

1051. As well, AltaLink submitted that the Commission has repeatedly rejected proposals to accelerate depreciation. In this regard, AltaLink noted that in Decision 3424-D01-2016 in respect of AltaLink's 2015-2016 GTA, the Commission found that accelerated depreciation violated principles of gradualism and moderation.<sup>1181</sup> Similarly, in Decision 22853-D01-2018 in respect of EPCOR Energy Alberta GP Inc. Non-Energy regulated rate tariff application, the Commission declined to endorse accelerated depreciation without evidence that the predicted asset lives would change.<sup>1182</sup>

1052. AltaLink also rejected Fortis's explanation that its amortization rate for AESO contributions reflects the depreciation of its "financial asset" and, therefore, should reflect the service life characteristics of Fortis's distribution assets.<sup>1183</sup> AltaLink submitted that because the AESO contribution is related to transmission system assets, not distribution system assets, it therefore should reflect the relevant life characteristics of a transmission asset. AltaLink noted that if it had invested in the same asset, it would be depreciated in accordance with its transmission depreciation studies and mass property accounts and the resulting rate would reflect the underlying asset life.<sup>1184</sup>

### Commission findings

1053. The Commission agrees with the submission of AltaLink that depreciation rates should match the underlying service lives of utility assets. The Commission considers that the

<sup>1178</sup> Decision 2013-417 at paragraph 285; AltaLink also refers to "the Commission's refusals to accelerate depreciation rates" in Decision 3524-D01-2016, *AltaLink Management Ltd. 2015-2016 General Tariff Application* (May 9, 2016) at paragraphs 301-308 and Decision 22853-D01-2018, *EPCOR Energy Alberta GP Inc., 2018-2020 Non-Energy Regulated Rate Tariff Application* (October 4, 2018) at paragraphs 172-180, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 175.

<sup>1179</sup> Decision 2013-417 at paragraph 285, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 177.

<sup>1180</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 178.

<sup>1181</sup> Decision 3524-D01-2016, paragraphs 301-308, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 179.

<sup>1182</sup> Decision 22853-D01-2018, at paragraphs 172-180, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 179.

<sup>1183</sup> Transcript Volume 6, page 1100, lines 9-11.

<sup>1184</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 181.

amortization rate for AESO contributions should reflect the average service life of transmission assets. Accordingly, the use of an amortization rate reflecting the average service life of distribution assets is not consistent with this principle.

1054. The Commission finds AltaLink's contribution proposal addresses the mismatch between the service life used for AltaLink's tariff and the AESO contribution amortization rate used in Fortis's tariff.

### **8.1.3.5 Potential ratepayer benefits from AltaLink contribution proposal**

1055. AltaLink argued in its evidence that it is more expensive for distribution rate payers to have Fortis fund Fortis's AESO contribution.<sup>1185</sup> AltaLink calculated that Fortis's customers would be charged an average of \$5.5 million less per year during the 2018 to 2022 PBR terms if Fortis's AESO contributions were refunded to Fortis as proposed by AltaLink.<sup>1186</sup>

1056. Fortis provided a table in its evidence that attempted to show that there would be a net long-term cost savings to ratepayers in net present value (NPV) terms by keeping AESO contribution balances with Fortis.<sup>1187</sup>

1057. AltaLink responded in its rebuttal evidence that Fortis's NPV benefit calculation was in error.<sup>1188</sup> AltaLink submitted that its recalculation showed that for every \$100 million in AESO contributions, the NPV cost of service difference between AltaLink and Fortis arising from the adoption of AltaLink's contribution proposal would be \$5.7 million per \$100 million of contribution using a PV discount rate of 7 per cent or \$6.5 million per \$100 million of contribution if a PV discount rate of 8 per cent is used.<sup>1189</sup>

1058. In the oral hearing, the Fortis witness panel acknowledged that the benefit calculation prepared in Fortis's evidence was in error and agreed with the corrected values presented in AltaLink's rebuttal evidence.<sup>1190</sup>

1059. In argument, AltaLink noted that the Commission stated in Decision 2012-362 that it "remains interested in measures that would have the effect of facilitating a transfer of contributions from DFOs to transmission facility owners to enable the possibility that end-use customers could obtain the benefit of the lower return on equity allowed for transmission facility owners."<sup>1191</sup>

1060. AltaLink submitted that its calculations show AltaLink's lower amortization rate and lower embedded cost of debt would save ratepayers approximately \$40 million over the 2018 to 2022 PBR term.<sup>1192</sup> This calculation looks at the total nominal value to ratepayers if AltaLink were to assume the unamortized pre-2018 AESO contributions balance, as well as Fortis's 2018 to 2022 forecast AESO contributions via the refunding mechanism proposed by AltaLink.<sup>1193</sup>

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<sup>1185</sup> Exhibit 22942-X0342, paragraphs 112-118.

<sup>1186</sup> Exhibit 22942-X0342, paragraph 114.

<sup>1187</sup> Exhibit 22942-X0424, paragraph 129

<sup>1188</sup> Exhibit 22942-X0451, paragraphs 38-41.

<sup>1189</sup> Exhibit 22942-X0451, paragraph 39.

<sup>1190</sup> Transcript Volume 6, page 1076, lines 2-9.

<sup>1191</sup> Decision 2012-362 at paras 82 and 83, cited at Exhibit 22942-X0555, AltaLink argument, paragraph 88.

<sup>1192</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 89.

<sup>1193</sup> Exhibit 22942-X0342, paragraphs 113-114.

## Commission findings

1061. The Commission notes there is consensus between Fortis and AltaLink that the adoption of AltaLink's contribution proposal will produce a significant financial savings to rate payers when savings are calculated on an NPV basis. The Commission also considers the five year nominal savings to ratepayers of \$40 million as calculated by AltaLink as being persuasive as to the merits of AltaLink's proposal.

1062. In light of other findings in this section that the public interest is not harmed in any other material respect through the adoption of AltaLink's proposal, the Commission considers that the financial benefit, estimated at \$40 million during the 2018 to 2022 PBR term by AltaLink, is sufficient to warrant a decision to approve the AltaLink contribution proposal.

### 8.1.4 Implementation considerations

1063. Fortis submitted in its evidence that because the ISO tariff does not operate in isolation, any consideration of the AESO's contribution policy that might be undertaken in the 2018 ISO tariff application proceeding must necessarily include an assessment of whether, and to what extent, proposed changes may affect the Commission's overall ratemaking approach for both distribution and transmission utilities. Fortis submitted that such effects may be complex, particularly when considering the interplay between the PBR regime for distribution utilities and the cost of service ratemaking regime for transmission utilities.<sup>1194</sup>

1064. With respect to the effect of AESO contribution changes on Fortis's service area, Fortis noted in particular the fact that provisions within Fortis's tariff permit the flow through of a "Customer Transmission Contribution" to Rate 63 Large General Service customers.<sup>1195</sup> These provisions allow it to flow the price signal associated with the AESO contribution on a whole or partial pro rata basis to large distribution connected (Rate 63) customers if Fortis determines that the transmission facilities requested by the customer are optional in nature.<sup>1196</sup>

1065. In addition, Fortis noted that direction 10 of Decision 21538-D01-2017 in respect of Fortis's 2015 PBR capital tracker true-up application required Fortis to examine whether some form of pro rata sharing of AESO contributions to end-use customers that drive the need for AESO contributions is warranted.<sup>1197</sup> Fortis submitted that any proposed approach that would effectively prevent the communication of the AESO contribution price signal would be fundamentally at odds with the Commission's determination to investigate the pro rata sharing of AESO contributions to end-use customers.<sup>1198</sup> Fortis also expressed concern that the differential application of the ISO tariff to different market participants could incent "tariff shopping" by certain types of market participants.<sup>1199</sup>

1066. Considering the foregoing, Fortis expressed concern that AltaLink's contribution proposal would create uncertainty and complexity related to its implementation within the ISO and distribution tariffs, particularly with respect to the pro rata flow through of contributions to

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<sup>1194</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 79.

<sup>1195</sup> Section 7.2.2 - Other Contributions of FortisAlberta's currently approved Customer Terms and Conditions of Electric Distribution Service, cited at Exhibit 22942-X0424, Fortis evidence, paragraph 79.

<sup>1196</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 80.

<sup>1197</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 83.

<sup>1198</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 84.

<sup>1199</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 87.

large end-use load customers, DCGs and smaller downstream DFOs such as REAs and small municipalities.<sup>1200</sup> Fortis submitted that its concern is shared by the AESO because administrative burden was cited by the AESO as one of the reasons for not recommending a change in the contribution policy for DFOs.<sup>1201</sup>

1067. In addition to the changes that Fortis submitted would be required to alter the ISO tariff to accommodate the current proposal, it expressed concern that AltaLink's contribution proposal would also create great disruption and alteration to a number of related tariffs, including:

- each of the AltaLink, ATCO Electric, ENMAX, EPCOR, Lethbridge, and Red Deer TFO GTAs and related applications;
- each of the Fortis, ATCO Electric, ENMAX, EPCOR distribution tariff applications (DTAs) and their respective 2018 to 2022 PBR plans; and
- each of the REA and municipally owned distribution tariffs.<sup>1202</sup>

1068. Fortis reiterated its concern in its reply argument.<sup>1203</sup> Further, it submitted that the transfer of rate base arising from AltaLink's proposal would result in numerous tax and other implications that have not been assessed by AltaLink, the AESO or the Commission.<sup>1204</sup>

1069. AltaLink responded in its sur-reply argument that although Fortis provided some clarification in response to a Commission IR,<sup>1205</sup> Fortis provided no elaboration on its disruption claims in its reply argument submission.

1070. AltaLink submitted that Fortis was the only entity to raise such concerns that call into question the level of disruption to other entities claimed by Fortis.<sup>1206</sup> AltaLink stated that even if changes are required to the tariffs of other utilities to implement its proposal, such changes are justified because of the underlying reasons AltaLink has put forward for making its proposal, including compliance with legislation and removal of improper price signals. Further, any administrative burden associated with implementation is outweighed by the benefits of its implementation.<sup>1207</sup>

1071. With respect to Fortis's suggestion in its reply argument that adopting AltaLink's contribution proposal could create "numerous tax and other implications," AltaLink noted that the reference to Decision 23505-D01-2018<sup>1208</sup> cited by Fortis to support this statement is actually a reference by the Commission in that decision to a Fortis statement suggesting that a change to the treatment of customer contributions could have various effects, including "tax consequences." AltaLink submitted that the Commission should not rely on this statement because it is Fortis's position, not the Commission's. However, even if the referenced statement

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<sup>1200</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 89.

<sup>1201</sup> Exhibit 22942-X0129, paragraph 16, cited at Exhibit 22942-X0424, Fortis evidence, paragraph 89.

<sup>1202</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 91.

<sup>1203</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 91, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 36.

<sup>1204</sup> Decision 23505-D01-2018 at paragraph 16 and Exhibit 22942-X0437 at PDF pages 10-11 (FAI-AUC-2019FEB19-007), cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 36.

<sup>1205</sup> Exhibit 22942-X0437, FAI-AUC-2019FEB19-007.

<sup>1206</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 12.

<sup>1207</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 13.

<sup>1208</sup> Decision 23505-D01-2018, Commission-Initiated Review and Variance of Decision 22741-D01-2018 (November 7, 2018) at paragraph 16, cited at Exhibit 22942-X0579, Fortis reply argument, paragraph 36.

represented the Commission's view, it would be irrelevant because the current proposal has nothing to do with PBR rebasing. AltaLink conclude that because the current process is unlawful, any tax consequences are the "correct consequences."<sup>1209</sup>

### Commission findings

1072. On December 15, 2017, AltaLink filed a letter in this proceeding advising that it planned to file a proposal regarding the DFO customer contribution as part of its evidence in this proceeding. Following a consultation period, AltaLink filed its evidence on January 15, 2019.

1073. In a letter dated January 30, 2019, the Commission issued a ruling stating that the customer contribution policies of DFOs was an issue that the Commission wished to examine, and therefore the Commission considered that it would benefit from receiving evidence from Fortis on this issue. It then approved Fortis's request to file its evidence late. In the same ruling, the Commission set out a process for the filing and testing of Fortis's evidence through a round of IRs. The Commission also stated that it would determine whether there was a need for AltaLink to file rebuttal evidence following receipt of Fortis's responses to IRs. In a ruling dated March 1, 2019, the Commission permitted AltaLink to file rebuttal evidence.

1074. The Commission considers that Fortis has been aware of this issue for a significant period of time and was provided with the opportunity to submit evidence in response to AltaLink's proposal both in writing and through the oral hearing. Further, the Commission asked Fortis in an IR to fully explain the changes to the tariffs that would be required in the event that AltaLink's proposals were adopted.<sup>1210</sup> Fortis provided a general discussion of possible changes that may be required. It did not identify tax consequences in its response.

1075. The Commission notes that during the hearing the Commission did not hear that Fortis was suggesting sweeping changes being required to implement the AltaLink proposal. Further, the Commission notes that the other distribution utilities did not raise complexity of implementation with respect to AltaLink's contribution proposal as a concern.

1076. The Commission accepts that implementation of AltaLink's proposal will require changes to the tariffs of parties affected by its implementation. However, given the limited nature of the evidence presented by Fortis in its IR response, the Commission is not persuaded that on balance, the effort to implement these changes outweighs the public interest that a significant financial savings to rate payers will be achieved through the adoption of AltaLink's contribution proposal.

1077. The Commission further notes that any distribution utility under PBR has the opportunity to address issues arising from new developments in the context of annual PBR adjustment filings. Accordingly, if Fortis has specific concerns related to the effect of the AltaLink contribution proposal that have not been taken into account in this proceeding, Fortis can use that mechanism to alert the Commission as to any adjustments it believes should be made to its tariff.

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<sup>1209</sup> Exhibit 22942-X0589, AltaLink sur-reply argument, paragraph 26.

<sup>1210</sup> Exhibit 22942-X0437.

### 8.1.5 Overview of the Commission's conclusions

1078. The Commission makes the following findings with respect to the AltaLink's proposed customer contribution proposal:

- The current accounting treatment of Fortis's AESO contributions is not inconsistent with the statutory scheme.
- Certain contribution policy objectives designed to promote the harmonized treatment of end-use customers that had been set out in prior decisions in respect of the ISO tariff would not be adversely affected if AltaLink's contribution proposal were to be adopted by the Commission.
- AltaLink's contribution proposals cannot be rejected on the basis of discrimination against "pure-play" DFOs.
- The UAD Decision does not compel the Commission to direct the AESO to adopt AltaLink's contribution proposal.
- The treatment of unamortized contribution balances proposed by AltaLink as part of its contribution proposal does not constitute retroactive rate making.
- The size of Fortis's AESO contribution balances in relation to the AESO contribution balances of other Alberta DFOs is significant and the Commission is not satisfied that it can be explained entirely by differences in the size and scope of Fortis's operations.
- To the extent that Fortis prioritizes its projects first based on capacity and then on reliability levels, it is reasonable for the Commission to conclude that Fortis is not motivated to advance these facilities in order to earn a return on the customer contribution portion. Consequently, Fortis should be indifferent about AltaLink's proposal because the proposal keeps Fortis financially whole with respect to the payment and refund of contributions.
- AltaLink's proposal matches the service life characteristics of the assets to be depreciated.
- The adoption of AltaLink's contribution proposal can result in a material financial benefit to ratepayers and is therefore in the public interest.

1079. Accordingly, the Commission directs the AESO, in its refiling, to consult with AltaLink and for the AESO and AltaLink to provide a joint proposal for the implementation of AltaLink's contribution proposal.

### 8.2 Terms and conditions: Construction contributions: Classification of projects to replace isolated generation

1080. ATCO Electric sought to connect Jasper, an isolated community under the *Isolated Generating Units and Customer Choice Regulation* (IGUCCR) to the AIES. ATCO Electric was informed by the AESO that to connect the Jasper community to the AIES, that it would need to initiate a SASR. SASRs are initiated by a DFO and submitted to the AESO. The AESO reviewed ATCO Electric's SASR and determined the project was a participant related project. Participant-related projects require the DFO to contribute to the cost of the project, subject to the AESO's maximum investment level contribution policy (as opposed to a system project where all transmission ratepayers would cover the costs).

1081. ATCO Electric, in its evidence, raised the issue with the AESO's approach to classifying facility costs as system costs or participant costs, in particular with regards to how it classifies

projects to replace isolated generation units. ATCO Electric proposed changes to the terms and conditions of the ISO tariff that would allow a TFO to initiate a SASR and automatically classify connection projects as system-related when they involve isolated communities. ATCO Electric proposed changes (underlined) as follows:<sup>1211</sup>

### **Section 3 – System Access Service Requests**

3.1(1) a **market participant** who has requested a new **system access service** or changes to an existing **system access service** under:

- (a) Rate DTS, *Demand Transmission Service*;
- (b) Rate FTS, *Fort Nelson Demand Transmission Service*;
- (c) Rate PSC, *Primary Service Credit*; or
- (d) Rate STS, *Supply Transmission Service*.

3.1(2) a TFO applying for a change in existing system access service which requires construction of Transmission Facilities to replace existing Transmission Facilities with similar capabilities.

### **Section 4 – Construction Contributions for Connection Projects**

4.2(4) In circumstances where the costs of serving an isolated community are recovered through the TFO tariff pursuant to the Isolated Generation and Customer Choice Regulation, if a proposed interconnection to the AIES is determined to be in the best interest of customers, the proposed interconnection project will be classified as a system project, regardless of whether it is initiated from a DFO SASR, by the AESO or by the relevant TFO, and the associated costs will be classified as system-related.

4.2(5) System-related costs are the costs of the connection project that have not been classified as participant-related in accordance with subsection 4.2(2), and (3), and (4) above, and include incremental **transmission** facilities costs in excess of the **ISO's** preferred connection alternative in accordance with subsection 3.4(1) of the **ISO tariff**, *System Access Service Requests*, to serve the **market participant(s)** where, as determined by the **ISO**, economics or **transmission system** planning support the development of such facilities.

1082. ATCO Electric advocated that the changes to the terms and conditions were required for several reasons, including the following:<sup>1212</sup>

- No available mechanism currently exists within the currently approved terms and conditions for projects to be initiated by the TFO under a SASR to be considered System Projects.
- Terms and conditions changes are required to ensure the AESO determines the best interests of customers in the safe, reliable and economic operation of the Alberta interconnected electric system.
- Transmission interconnection of isolated communities operate to the benefit of many transmission-connected market participants

<sup>1211</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 4-5

<sup>1212</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11



- Isolated generation facility costs are recovered through TFO tariffs, pursuant to Decision 2001-42.

1083. ATCO Electric explained that through discussions with the AESO, the only way it was able to proceed with the Jasper Interconnection project was to initiate the project under a DFO SASR. It contended that “[i]f there was an appropriate mechanism for an interconnection of an isolated community within the AESO’s T&C [terms and conditions], ... the Jasper Interconnection project would not have required a DFO SASR, and therefore would not have been determined to be a connection project by the AESO in accordance with its interpretation of the Terms and Conditions and the applicable legislation.”<sup>1213</sup> ATCO Electric argued that a SASR initiated by a DFO should not automatically dictate that a project be classified as a participant cost.<sup>1214</sup>

1084. ATCO Electric maintained that the *Isolated Generating Units and Customer Choice Regulation* (IGUCCR) does not address the treatment of isolated generation assets built pre-deregulation. ATCO Electric further stated that similar projects, in which generation assets built pre-deregulation were eventually replaced by interconnection to the AIES, were historically considered to be system projects.<sup>1215</sup>

1085. ATCO Electric expressed concern with the AESO’s response to an ATCO Electric IR in which the AESO responded that it does not consider itself to have a role in determining the interconnection of isolated communities.<sup>1216</sup> ATCO Electric stated that in its view, “the AESO should have a role in the determination of whether a community should continue to be served by isolated generation, or interconnected to the grid.”<sup>1217</sup>

1086. ATCO Electric explained that if it were to refurbish an existing isolated generation facility, all of its prudently incurred costs would be included in the AESO’s tariff and those costs in the AESO’s tariff would be recovered from all Alberta customers. ATCO Electric argued that the AESO’s approach to the Jasper Interconnection wrongly subjects ATCO Electric’s distribution customers, rather than all Alberta ratepayers, to the project risks.<sup>1218</sup>

1087. ATCO Electric explained that no mechanism exists under the current terms and conditions for initiating and completing an interconnection as a system cost. ATCO Electric argued, “[t]o the extent transmission interconnection was determined to be the prudent form of serving the community and where previously the generation costs were borne by all ratepayers, then from a public interest perspective, the AESO has made the determination that ALL provincial ratepayers benefit from interconnection of the community. On that basis, all ratepayers should then share in the interconnection costs of connecting the community to the grid. This is the best option for all ratepayers, not just those of the relevant DFO.”<sup>1219</sup>

1088. The AESO, in its rebuttal evidence, disputed ATCO Electric’s assertion that because a SASR was submitted, a project is automatically deemed a participant cost. The AESO stated that

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<sup>1213</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1214</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1215</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1216</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1217</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1218</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

<sup>1219</sup> Exhibit 22942-X0333, ATCO Electric evidence, PDF pages 5-11.

the characteristics of a project determine whether it is a connection project or a system project, not the process required to initiate that project. The AESO explained that the Jasper project would be considered a connection project, and consequently classified as participant, because the system access service was to a single load point of delivery and involved radial transmission facilities. The AESO further explained that a “system project does not involve system access service to a single load point of delivery and characteristically comprises of non-radial transmission facilities that increase the number of electrical paths between two substations, to the benefit of many transmission-connected market participants.”<sup>1220</sup>

1089. The AESO agreed with ATCO Electric that its duty is “to direct the safe, reliable and economic operation of the interconnected electric system,” however, it disputed ATCO Electric’s statement that it “should have a role in the determination of whether a community should continue to be served by isolated generation, or interconnected to the grid.” The AESO explained that isolated communities are not part of the interconnected electric system. Isolated communities only become part of the interconnected electric system once they have been provided with system access service on the transmission system.<sup>1221</sup>

1090. The AESO stated that consistent with all connection projects, costs related to the connection of an isolated community should be assumed to be participant-related, unless it can be demonstrated that it provides a system benefit to many transmission-connected market participants. The AESO added that “the facilities involved in the connection of an isolated community clearly align with those described as participant-related for a connection project in subsection 4.2(2) of the proposed ISO tariff, in particular, the connection substation for the point of delivery, a radial circuit with only one transmission source from the transmission system to the connection substation, and breakers and changes to protection systems, equipment or settings required for the connection project at an existing substation.”<sup>1222</sup>

1091. The AESO demonstrated how costs classified as participant-related or system-related may be affected differently by changes to the transmission system in the future:

For example, connection project transmission facilities may in the future be utilized to provide system access service to another market participant. If the cost of the facilities were classified as participant-related, a share would be allocated to and recovered from the second market participant. If the costs were classified as system-related, they would continue to be recovered from all market participants. The AESO considers the potential to have costs allocated to and recovered from the second market participant to be an important feature of classifying costs as participant-related, as it is for most connection projects.<sup>1223</sup>

1092. The AESO stated that connection costs are only of benefit to all market participants if they represent the least cost option for providing electricity to an isolated community. It explained, similar to the approach adopted by the AESO for the Jasper Interconnection Project, this can be achieved by setting the maximum investment level to the net present value of the ongoing costs of isolated generation.<sup>1224</sup> The AESO submitted that through its ability to exercise its discretion with respect to the construction contribution provisions in the ISO tariff, a case-by-

<sup>1220</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 130.

<sup>1221</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 131.

<sup>1222</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 132.

<sup>1223</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 133.

<sup>1224</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 134.

case determination of maximum investment level will properly allow such considerations to be assessed. It added that this is “in contrast with ATCO Electric’s recommendation that the connection costs be classified as system-related, which would provide no constraints on the costs that could be considered system-related.”<sup>1225</sup>

1093. The AESO considered that a reasonable approach to the treatment of isolated community connection costs would result in:<sup>1226</sup>

- (a) the project being treated as a connection;
- (b) its costs classified as participant-related;
- (c) the maximum investment level being based on avoided costs of isolated generation while accounting for technical and public interest considerations; and
- (d) prudently incurred costs being considered similarly.

1094. ATCO Electric, in its argument, stated that “the circumstances surrounding the classification of the costs of the Jasper Interconnection Project serve to illustrate the problems associated with the AESO’s interpretation of its current Terms and Conditions; and the perverse results which are arising from the AESO’s rigid interpretation of its existing contribution policy,” and that its proposed amendments to the AESO terms and conditions would ensure that a fair and reasonable end result is achieved.<sup>1227</sup>

1095. ATCO Electric maintained that the terms and conditions do not consider the unique circumstances surrounding the interconnection of isolated communities to the grid. It explained that, under the terms and conditions associated with the current ISO tariff, ATCO Electric is required to classify the costs for the Jasper Interconnection project as participant related, whereas such costs associated with the provision of transmission service to Jasper had been classified consistently as system related in the past. ATCO Electric added that the classification of costs is discriminatory as it would lead to customers in ATCO Electric’s service area paying more for transmission service, which was previously collected from all provincial ratepayers.<sup>1228</sup>

1096. ATCO Electric stated that it should face incentives that ensure that when determining when and how to replace existing isolated generation facilities that are facing an end of life replacement, an optimal outcome will ensue. ATCO Electric argued that the optimal result should not lead to an outcome that reclassifies the costs of providing transmission services from system to participant.<sup>1229</sup>

1097. ATCO Electric acknowledged that in the Jasper Interconnection project, the AESO’s investment policy resulted in an offset to the project costs, such that the project costs were recovered from all ratepayers. However, ATCO Electric still took issue with the terms and conditions that do not address its issue of the classification and allocation of project costs as system or participant. ATCO Electric argued the current terms and conditions may result in

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<sup>1225</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraphs 135-136.

<sup>1226</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraph 137.

<sup>1227</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 8.

<sup>1228</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 16.

<sup>1229</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 17.

additional costs to a DFO, when instead they should be treated as they were in the past, which was to treat them as system costs.<sup>1230</sup>

1098. In ATCO Electric's argument, it disagreed with the AESO application of its terms and conditions on the Jasper Interconnection, as it argued that the project is not a connection project as defined in Section 4 of the existing terms and conditions. Section 4 states that a market participant must apply to the AESO to request a new system access service or a change to an existing system access service. ATCO Electric argued the Jasper Interconnection project does not fall into either of these categories, as Jasper was not a new system access service for a new POD, nor was there a need to change the existing System Access Service Agreement. It argued that a POD that supports the interconnection of the isolated generation plant already existed, an interconnection was not required to facilitate an expansion of load and, as a result, the project was not properly classified as a connection project, as defined within the AESO's existing terms and conditions. ATCO Electric asserted that the AESO's position on this matter reaffirms the need for the amendments to the existing Terms and Conditions advanced by ATCO Electric, which would provide a mechanism to enable the TFO to initiate a project in these circumstances.<sup>1231</sup>

1099. ATCO Electric submitted that projects that replace existing transmission assets, such as the proposed Jasper Interconnection project, will continue to provide service and address a need similar to the existing arrangement. It stated that the costs related to the replacement of existing assets that are a proxy for transmission assets should appropriately be classified as system costs.<sup>1232</sup>

1100. ATCO Electric argued that the position adopted by the AESO on the Jasper Interconnection project is inconsistent with how it interprets and applies the terms and conditions in other instances that ATCO Electric submitted should be viewed as comparable. It stated, "[f]or example, if a system line needs to be reconducted or rebuilt because it is at the end of life, to the extent that customers may be impacted by the transmission activity, the DFO would be made aware of the work and the TFO would initiate the project as a capital maintenance project, as there would be no new POD and no new load. In those cases, the new asset would continue to be appropriately treated as system, just as the prior facilities were."<sup>1233</sup>

1101. In ATCO Electric's view, "[h]ad ATCO Electric simply replaced the isolated generation with another generating unit, the costs would have continued to be treated as transmission costs that are borne by all Alberta ratepayers. However, by doing the right thing and pursuing the optimal solution the costs have now been reclassified as participant. This result is simply not sensible nor fair. ATCO Electric submits that there is simply no basis to support this perverse outcome."<sup>1234</sup>

1102. ATCO Electric submitted that the determination of costs to serve Jasper being classified as system costs would be consistent with the public interest, as all provincial ratepayers benefit from providing transmission services to the community. It suggested that all ratepayers should, therefore, share in the interconnection costs, regardless of whether transmission service is

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<sup>1230</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 18.

<sup>1231</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 20.

<sup>1232</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 21.

<sup>1233</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 22.

<sup>1234</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 24.

provided by an interconnection to the AIES or by a replacement of generation assets. ATCO Electric argued that the best decision on the delivery of electricity service should not result in a reclassification of costs such that DFO customers would bear the costs of the project instead of all ratepayers.<sup>1235</sup>

1103. ATCO Electric submitted that another unintended consequence of the manner in which the AESO is applying its existing terms and conditions is that it results in discrimination in the provision and pricing of service. It argued that the AESO is driving the system versus participant decision regarding the requirement for a SASR and the classification of radial lines as participant; and this has resulted in a different standard of service being provided to customers by virtue of their location on the system. These customers are being penalized with higher distribution charges for the transmission service they receive, when previously, the costs of the same transmission service was allocated to all customers across the province. ATCO Electric submitted that this is inconsistent with the postage stamp principle that is embedded in Section 30(3)(a) of the *Electric Utilities Act*. The AESO's interpretation of its existing terms and Conditions has resulted in transmission costs being shifted inappropriately to a specific DFO, instead of being borne by all ratepayers in the province. In the end result, ATCO Electric is incurring higher distribution charges arising from higher distribution to transmission contributions, in addition to higher transmission charges arising from the AESO's cost classification-study. This results in customers being charged different rates for transmission service based on their location in the province. ATCO Electric submitted that this result is inconsistent with both the wording and the intent of the legislation.<sup>1236</sup>

1104. ATCO Electric claimed the interpretation and application of the current terms and conditions by the AESO is putting upward pressure on distribution rates due to the increase in the DFO to TFO contributions. It asserted the result has occurred due to changes in the treatment of costs that should be averaged across the province and charged to all ratepayers. This would not occur if the project costs were properly classified as system, which it argued should be the case.<sup>1237</sup> ATCO Electric asserted that "to the extent that its distribution customers are paying more for transmission service, in comparison to other distribution customers in the Province, it moves away from the postage stamp principle that is designed to ensure that customers, no matter where they are located in the Province, pay roughly the same transmission charge."<sup>1238</sup>

1105. The AESO, in its argument, stated that the *Electric Utilities Act* defines system access service as "the service obtained by market participants through a connection to the transmission system." The AESO pointed out that isolated communities are not connected to the transmission system and, therefore, cannot be receiving system access service. Accordingly, there is a requirement for a new system access service to connect an isolated community to the transmission system.<sup>1239</sup>

1106. In addition to the Jasper Interconnection project, the AESO identified three other isolated communities that had been, or are in the process of being, connected to the Alberta interconnected electric system since 1995: Cranberry Lake-Kidney Lake, Fox Lake, and Garden

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<sup>1235</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 25.

<sup>1236</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 26.

<sup>1237</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 27.

<sup>1238</sup> Exhibit 22942-X0553, ATCO Electric Argument, paragraph 29.

<sup>1239</sup> Exhibit 22942-X0558, AESO argument, paragraph 191.

River. In its response to an AESO's IR<sup>1240</sup>, ATCO Electric was unable to demonstrate that the connection costs for those communities had been classified as system-related and recovered through the ISO tariff after connection. The AESO explained that the provision proposed by ATCO would result in the classification of the connection costs for an isolated community being system-related and recovered through the ISO tariff, regardless of whether the connection involves transmission facilities or distribution facilities. Based on ATCO Electric's proposal, the connection of Fox Lake would have had all of its costs classified as system-related, despite there being no transmission costs related to the Fox Lake connection. The AESO submitted that such an outcome would be inappropriate and that the provision proposed by ATCO Electric should be rejected.<sup>1241</sup>

1107. With respect to the AESO's proposed classification of costs for transmission facilities to connect an isolated community, the AESO submitted that ATCO Electric has incorrectly interpreted the legislation, has not demonstrated any "perverse" outcomes, and has proposed a provision that would inappropriately classify costs. The AESO indicated that ATCO Electric's proposed provision should be rejected, and the new provision proposed by the AESO in subsection 4.2(2)(m) of the 2018 ISO tariff should be approved as filed.<sup>1242</sup>

1108. In its reply argument, ATCO Electric submitted that based on the evidence and argument filed in this proceeding, the current approach adopted by the AESO for the classification of connection costs for isolated communities reflects a broader problem that needs to be addressed in the AESO's next tariff application.<sup>1243</sup>

1109. In reply argument, the AESO stated that ATCO Electric has incorrectly presumed that an isolated community already receives system access service through a transmission facility.<sup>1244</sup> In addition, the AESO stated ATCO Electric's interpretation of the *Isolated Generating Units Regulation* provision that it must pay the AESO "as if the isolated community were being provided with system access service via the interconnected electric system" as meaning that the isolated community actually receives system access service is incorrect.<sup>1245</sup>

1110. The AESO maintained that the mechanism that is established by the legislative scheme, including the ISO tariff, was a system access service request for the connection of Jasper. That mechanism resulted in a connection project that was approved in Decision 22125-D01-2018. The AESO argued that "[s]imply because the mechanism that was followed did not align with ATCO Electric's preferred approach does not mean there was no mechanism available."<sup>1246</sup>

1111. The AESO claimed that the mechanism of a system access service request provides an appropriate price signal because it requires the DFO to be accountable for the costs associated with its request to connect the isolated community, exactly as the DFO must be for any other system access service it requests to serve any community in its service area. The AESO added

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<sup>1240</sup> Exhibit 22942-X0417, ATCO Electric IR to AESO, ATCO-AESO-2019JAN28-002.

<sup>1241</sup> Exhibit 22942-X0558, AESO argument, paragraph 196.

<sup>1242</sup> Exhibit 22942-X0558, AESO argument, paragraph 197.

<sup>1243</sup> Exhibit 22942-X0572, ATCO Electric reply argument, paragraph 13.

<sup>1244</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 145.

<sup>1245</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 143.

<sup>1246</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 146.

that the mechanism uses the same approach for all requests for system access services to communities served by DFOs.<sup>1247</sup>

1112. The AESO submitted that the cost classification of the Jasper Interconnection project was consistent with the cost classification of other connection projects. The AESO referred to Decision 2010-606, where the Commission had found that isolated generation costs should be classified “on the same (proportional) basis as the AESO uses to classify all other local and POD costs.” The AESO considers that the Commission’s finding that costs should be classified similar to other facilities is consistent with the AESO’s approach of classifying the costs similar to other connection projects. Classification similar to other connection projects results in costs being classified as participant-related unless they are associated with specific types of facilities set out in the ISO tariff. The costs related to the Jasper Interconnection project were not associated with any of the specific types of facilities that give rise to costs being classified as system-related.<sup>1248</sup>

1113. In its reply argument, the AESO reiterated that “[t]he maximum investment level for the connection of an isolated community should be transparently determined by setting it to the net present value of the ongoing costs of isolated generation, with the AESO exercising its discretion if necessary to account for technical and public interest considerations.” If the maximum investment level covers the cost of the connection project, those costs will be recovered through the ISO tariff from all transmission system access services.<sup>1249</sup>

1114. The AESO disputed ATCO Electric’s view that its interpretation and application of the terms and conditions offend the postage stamp principle, and stated that contributions from the distribution utility do not offend the postage stamp principle, pursuant to Decision 2005-096, where the board stated:<sup>1250</sup>

In this regard, the Board notes that it was previously determined in Decision 2001-[0]6 that the AESO’s predecessor would not violate the principle of postage stamp rates by adopting a contribution policy that could require some distribution utilities to pay somewhat higher contributions than other distribution utilities....

The Board considers that it is both consistent with past practice and consistent with the desire to send efficient pricing signals through the contribution policy that customer contribution costs incurred by a distribution utility should be recovered through the distribution utility’s own tariff.<sup>1251</sup>

### Commission findings

1115. Under the current terms and conditions, a TFO cannot initiate a SASR, and the AESO has not proposed any change to this section of the tariff. ATCO proposed changes to the existing terms and conditions that would allow a TFO to initiate a SASR, and would automatically classify the costs of connection projects to currently identified isolated communities as system-related costs.

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<sup>1247</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 147.

<sup>1248</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 148.

<sup>1249</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 150.

<sup>1250</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 151.

<sup>1251</sup> Decision 2005-096: Alberta Electric System Operator (AESO), 2005/2006 General Tariff Application, Application 1363012, August 28, 2005, page 52.

1116. In considering ATCO Electric's proposal, the Commission must determine whether the statutory framework for providing service to isolated communities, as well as the duties of DFO's and TFO's, as defined in the EUA, would permit the adoption of the amended terms and conditions into the 2018 ISO tariff.

1117. Some remote Alberta communities, defined as "isolated communities" in the IGUCCR, are not connected to the Alberta inter-connected electric system (AIES) because they are located far away from existing transmission lines and it is more economical to provide electricity directly to those communities through local power plants, called "isolated generating units" and a local distribution system. The cost of isolated generation to serve "isolated communities" is recovered through the ATCO Electric TFO tariff, pursuant to the IGUCCR. As a result, isolated generation costs are recovered from all rate payers across the system.

1118. It is the responsibility of the DFO to make electric energy available to the isolated community. With respect to isolated generation, Section 2 of the IGUCC, states:

**Duty to make electric energy available**

- 2 The owner of the electric distribution system in whose service area an isolated community is located

Must make electric energy available to customers in the isolated community,  
and

...

1119. Section 105 of the *Electric Utilities Act* states:

**Duties of owners of electric distribution systems**

105(1) The owner of an electric distribution system has the following duties:

- (a) to provide electric distribution service that is not unduly discriminatory;
- (b) to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy having regard to managing losses of electric energy to customers in the service area served by the electric distribution system;

...

(d) if a transmission facility serves only one service area, to arrange for the provision of system access service to customers in that service area, other than customers referred to in section 101(2);

...

(h) to undertake financial settlement with the Independent System Operator for system access service;

...

(k) to connect and disconnect customers and distributed generation in accordance with the owner's approved tariff and with principles established by the Commission regarding distributed generation;



1120. Both Section 2 of the IGUCC and Section 105 of the *Electric Utilities Act* specify that it is the responsibility of the DFO to obtain a source of electricity and determine the reliability of the electricity provided to the customers in its service area. Specifically, Section 105(1)(d) states that it is the DFO's responsibility to arrange for the provision of system access service to customers in its service area, and Section 105(1)(k) states that a DFO has the responsibility to connect and disconnect customers. TFO's have the following duties prescribed to them in Section 39 of the *Electric Utilities Act*, provided below, and are responsible to operate and maintain their facilities within the AIES.

**Duties of transmission facility owners**

39(1) Each owner of a transmission facility must operate and maintain the transmission facility in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system.

(2) Each owner of a transmission facility must, in a timely manner, assist the Independent System Operator in any manner to enable the Independent System Operator to carry out its duties, responsibilities and functions.

...

1121. It is the duty of the DFO to arrange for the provision of system access service to customers in its service area. As discussed above, isolated communities are not connected to the AIES. The Commission disagrees with ATCO's argument that the ISO tariff's terms and conditions do not consider the unique circumstances surrounding the interconnection of isolated communities to the grid. Isolated communities are not connected to the grid and, as such, a request to connect to the AIES is required; this request should be treated by the AESO in a manner that is similar to how the AESO would treat any other SASR.

1122. The Commission finds that ATCO's proposed changes to the 2018 ISO tariff's terms and conditions that would allow for a TFO to submit a SASR, would contravene the duties and responsibilities of a DFO, which are to determine and provide for a reliable supply of electric energy to an isolated community, and to arrange for the provision of system access service to customers in its service area.

1123. The AESO has demonstrated how costs classified as participant-related or system-related could be affected by changes to the transmission system in the future. ATCO Electric's proposal, to automatically classify connection projects as system-related when they involve isolated communities, could constrain the AESO's ability to recover a portion of the participant-related costs from another market participant that uses the same transmission facilities.

1124. The AESO's approach to the treatment of isolated community interconnection being treated as a connection project and being classified as participant related is consistent with other projects seeking interconnection to the AIES. The Commission finds the AESO's treatment of connections of isolated communities to the AIES is practical and reasonable. Further, the Commission finds that the AESO's authority to exercise its discretion regarding the application of its contribution policy, as found in Section 4.10 of the AESO's tariff and discussed further in Section 7.2.5.2 of this decision, by setting the maximum local investment level to the net present value of the ongoing costs of isolated generation and accounting for technical and public interest considerations, provides a reasonable determination of whether it is economical for an isolated community to connect to the AIES or replace a generating unit, while providing an appropriate

price signal to the DFO to be accountable for the costs associated with its request to connect the isolated community.

1125. ATCO Electric stated that instead of providing a transmission solution for the Jasper project, it could have chosen to replace the existing generating units to continue to serve the Jasper area as an isolated community. If that approach had been adopted, the project would have been completed as a capital maintenance project by the TFO and the associated costs would have continued to be included in the TFO's revenue requirement and passed on to the AESO, to be paid for by all provincial ratepayers.<sup>1252</sup>

1126. ATCO Electric's proposal that it could have just replaced the existing generating units as a capital maintenance project, and had the costs recovered through its TFO tariff, is not accurate. Under the IGUCC Regulation, the owner of a distribution system that serves an isolated community must file an application with the Commission if it determines that it is necessary to replace an isolated generating unit or add an isolated generating unit to maintain a reliable supply of electric energy, or provide more electric energy, to the isolated community. Therefore, the DFO must first evaluate and explore whether connecting to the AIES or replacing the isolated generating unit is more economical. This is provided in Subsection 27(1.1) of the IGUCC Regulation, which states that the Commission may approve the replacement of an isolated generating unit application if, in its opinion, it is not economical to connect the isolated community to the AIES. Specifically, Section 27 states:

**Reliable supply or increased load**

**27(1)** Where, in order to maintain a reliable supply of electric energy or to provide more electric energy to an isolated community or industrial area,

- (a) an isolated generating unit is to be replaced, or
- (b) an additional isolated generating unit is required,

an owner must apply to the Commission for approval of the replacement or additional generating unit.

**(1.1)** If the Commission receives an application under subsection (1), the Commission may approve the application if, in the opinion of the Commission, the connection of the isolated community or industrial area to the interconnected electric system is not economic.

1127. The Commission is not persuaded that ATCO Electric's proposed amendments to the 2018 ISO tariff's terms and conditions should be adopted. The Commission finds that the proposed changes would treat the connection of isolated communities differently than other connection projects, contravene legislated duties of a DFO, and could prevent the AESO from recovering a portion of the participant-related costs from another market participant that uses the same transmission facilities. ATCO Electric's proposed amendments to the AESO's 2018 ISO tariff are denied.

### **8.3 Terms and conditions: Construction contributions: Determination of optional facilities/GEIP**

1128. In Decision 2010-606 the Commission approved the AESO's proposal to delegate the determination of good electric industry practice (GEIP) to TFOs provided that the AESO reviews

<sup>1252</sup> Exhibit 22942-X0572, ATCO Electric reply argument, paragraph 20.

and approves any determination prepared under that delegation to ensure that there is non-discriminatory access to the system for all market participants.<sup>1253</sup> The Commission also requested that the AESO prioritize its development of connection process guidelines respecting the distribution point of delivery interconnection process.<sup>1254</sup>

1129. In an IR to the AESO (AESO-AUC-2018NOV01-019),<sup>1255</sup> the Commission asked the AESO to explain its progress with respect to the development of point of delivery process guidelines. The IR also sought clarification regarding how the AESO has incorporated the point of delivery process guidelines in light of the Commission's findings in Decision 2010-606.

1130. The AESO responded that the content in the guidelines was either incorporated into the technical requirements of an ISO rule or replaced by the AESO's redesigned connection process. The AESO advised that it considers the market participant requesting system access service to be in the best position to assess the reliability, capacity and operational requirements of its requested connection. Therefore, if the AESO considers connection facilities requested by a market participant to be reasonably required to meet the market participant's requirements, the AESO's practice is to deem those facilities not in excess of GEIP.

1131. In argument, the AESO reiterated its response to AESO-AUC-2018NOV01-019.<sup>1256</sup> It added that it is unlikely that the AESO would select a connection alternative for a market participant with facilities that it considered to be in excess of GEIP because subsection 3.4(1) of its proposed 2018 ISO tariff requires it to select the lowest overall long-term cost option for connection projects as part of the AESO's connection process.<sup>1257</sup> The AESO also considered that connection facilities in excess of GEIP would go beyond the requirement under section 29 of the *Electric Utilities Act* to provide market participants with a "reasonable" opportunity to exchange electric energy and ancillary services.<sup>1258</sup> Further, it noted that where a market participant's system access service request can be facilitated at a lower cost through a distribution-only solution, the AESO would not support moving forward with a transmission facility project for the connection.<sup>1259</sup>

1132. The AESO advised that, to date, it has not considered it to be necessary to exercise its discretion to deem connection facilities to be in excess of GEIP. However, the AESO noted that the Grist Lake project, which the AESO panel discussed with Commission counsel, could be deemed to have facilities in excess of GEIP if Fortis determines that it could provide a reasonable service through a distribution solution and the customer opts to have a transmission connection.<sup>1260</sup>

1133. In the oral hearing, Mr. Martin, on behalf of the AESO, indicated that as the project already required a substantial contribution, it was unlikely that the identification of facilities in excess of GEIP would have increased the amount of the contribution. Furthermore, Mr. Martin explained that, to the extent that the end-use customer for the Grist Lake project has indicated a

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<sup>1253</sup> Decision 2010-606, paragraph 390.

<sup>1254</sup> Decision 2010-606, paragraph 395.

<sup>1255</sup> Exhibit 22942-X0257, AESO-AUC-2018-NOV01-019, PDF page 34.

<sup>1256</sup> Exhibit 22942-0558, AESO argument, paragraph 114.

<sup>1257</sup> Exhibit 22942-X0163, Amended application, Section 7.3.7; Exhibit 22942-X0014.03, Section 3.4(1), PDF pages 56-57.

<sup>1258</sup> Exhibit 22942-0558, AESO argument, paragraph 115.

<sup>1259</sup> Exhibit 22942-0558, AESO argument, paragraph 116.

<sup>1260</sup> Exhibit 22942-0558, AESO argument, paragraph 119.

willingness to pay a \$37 million contribution, it is likely that the end-use customer would pay a higher amount, due to the importance of completing the connection.<sup>1261</sup> The AESO submitted that Mr. Martin's explanation reflects the AESO's view that its current construction contribution approach sends an effective price signal and that trying to fine tune the details of GEIP would not improve that signal.<sup>1262</sup>

1134. The AESO also acknowledged the recent AUC decisions, approving with dissenting reasons, the needs identification documents for the Provost reliability and Fincastle substation projects. The AESO submitted that although these decisions would not affect the AESO's approach to the exercise of its discretion under the GEIP provisions of the ISO tariff, they would affect the AESO's approach to the review and scrutiny of system access service requests that the AESO receives from DFOs.<sup>1263</sup>

### Commission findings

1135. As noted above, the Commission approved the AESO's proposal to eliminate the concept of "AESO standard service" in Decision 2010-606. As discussed in Decision 2010-606, the AESO proposed the move from AESO standard service to GEIP in part because, as a practical matter, most customers were not satisfied with the reliability of electric service provided by AESO standard service. Recognizing that GEIP facilities required by market participants would provide a higher standard of service and would generally correspond to the facilities that customers would request for most connections, the AESO proposed a reduction in the level of investment coverage through a reduction in the maximum investment level multiplier that was designed to reflect the changed approach.<sup>1264</sup>

1136. The Commission also determined in Decision 2010-606 that although the AESO could delegate the determination of facilities in excess of GEIP to TFOs, the AESO should retain final oversight of GEIP and should review and approve any determination prepared under the delegation.<sup>1265</sup> As well, the Commission expected the AESO to develop distribution point of delivery interconnection process guidelines to support the determination of GEIP.<sup>1266</sup> However, in its response to AESO-AUC-2018NOV01-019(a), the AESO indicated that it did not carry out any work to establish distribution point of delivery process guidelines following the issuance of Decision 2010-606.<sup>1267</sup>

1137. Based on its review of the evidence in this proceeding provided by AltaLink in support of its contribution proposal, addressed in Section 8.1 of this decision, the Commission has questioned whether the benefit that the AESO's customers obtained through the reduction of the maximum level multiplier was sufficient to offset increases in the costs of transmission connections facilities resulting from the flexibility provided under the GEIP standard.

1138. Consequently, the Commission no longer considers that GEIP is preferable to the concept of AESO standard service. Although the AESO's standard service may have involved a configuration of connection facilities less than desired by most market participants, the

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<sup>1261</sup> Transcript, Volume 3, page 615.

<sup>1262</sup> Exhibit 22942-0558, AESO argument, paragraph 117.

<sup>1263</sup> Exhibit 22942-0558, AESO argument, paragraph 120.

<sup>1264</sup> Decision 2010-606, paragraph 444.

<sup>1265</sup> Decision 2010-606, paragraph 390.

<sup>1266</sup> Decision 2010-606, paragraph 395.

<sup>1267</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-019, PDF pages 33-34.

application of the AESO standard facilities criteria meant that the market participant requesting the connection facilities would be required to pay for any excess facilities, and would therefore be incented to manage this cost by ensuring that requested connection facilities are not in excess of the market participant's requirements. Further, the evidence reveals that the AESO has not considered it necessary to exercise its discretion to deem connection facilities to be in excess of GEIP.

1139. In light of the foregoing, the Commission would like to examine whether a return to the use of the AESO standard service definition, rather than the standard of facilities in excess of GEIP, should be used to determine optional facility costs. Accordingly, the Commission directs the AESO to address the Commission's findings in its next comprehensive ISO tariff application.

#### **8.4 Terms and conditions: Construction contributions: Contributions for line relocations**

1140. During the oral hearing, counsel for the CCA examined the AESO panel on the application of cost causation principles in instances where already constructed transmission lines that have been designated as a system line are moved at the request of a market participant.<sup>1268</sup> As part of this questioning, the CCA asked the AESO panel questions using cross examination aids related to the relocation of ATCO Electric transmission line 9L101.<sup>1269</sup>

1141. In its argument, ATCO noted that the cross examination aids related to transmission line 9L101 were based on exhibits related to the consideration of line 9L101 relocation issues within the context of ATCO's 2018 to 2019 GTA which was being considered in Proceeding 22742. ATCO submitted that questioning the AESO on a matter being actively considered in another proceeding was highly inappropriate and that the information regarding line 9L101 obtained through the examination of the AESO panel should be entirely disregarded by the Commission.<sup>1270</sup>

1142. In argument, the CCA submitted that it is generally supportive of the changes to the classification of costs as between system-related and participant-related that the AESO proposed in its application but that further improvements in the classification as between system-related and participant-related could be made through consultation with the AESO and within the next ISO tariff application.<sup>1271</sup>

1143. In this regard, the CCA noted that during the CCA's questioning of the AESO panel during the oral hearing, it was apparent from the AESO's testimony that if the market participant submits a SASR in respect of a line relocation, then that market participant would be responsible for the relocation costs.<sup>1272</sup> Conversely, if no SASR is filed in respect of a line relocation, the cost of the line relocation is not automatically deemed to be participant-related and is, instead, assessed on a case-by-case basis by the Commission.<sup>1273</sup>

1144. The CCA submitted that the AESO's practice of determining classification based on whether a system access service request has been filed may lead to inconsistencies between

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<sup>1268</sup> Transcript, Volume 3, pages 457-463.

<sup>1269</sup> Exhibits 22942-X0499 and 22942-X0500.

<sup>1270</sup> Exhibit 22942-X0553, ATCO Electric argument, paragraph 58.

<sup>1271</sup> Exhibit 22942-X0549, CCA argument, paragraph 65.

<sup>1272</sup> Transcript, Volume 3, page 462, lines 1-10, referenced at Exhibit 22942-X0549, CCA argument, paragraph 66.

<sup>1273</sup> Exhibit 22942-X0549, CCA argument, paragraph 67.

relocation projects with otherwise comparable facts. The CCA also expressed concern that this difference could also lead to ratepayers being unnecessarily burdened with costs that the market participant should pay for.<sup>1274</sup>

1145. The CCA submitted that despite section 4.10(1) of the proposed 2018 ISO tariff that states “[t]he ISO must make reasonable efforts to ensure that, where transmission facilities must be relocated, the party causing the relocation pays all reasonable costs associated with the relocation,”<sup>1275</sup> based on its examination of the 9L101 line relocation, the AESO has had no substantial involvement in the classification of the line relocation costs as system-related or participant-related.<sup>1276</sup>

1146. It submitted that the Commission should direct the AESO to provide a clear set of guidelines regarding how the AESO will discharge its duty to make reasonable efforts for cost recovery for line relocations not initiated by a system asset service request as part of its compliance filing.<sup>1277</sup>

1147. ATCO reiterated its view in its reply argument that the CCA’s questioning regarding the line relocation costs for transmission line 9L101 was inappropriate and should be entirely disregarded by the Commission.<sup>1278</sup>

1148. The AESO agreed with ATCO’s position in its reply argument.<sup>1279</sup> It argued that the CCA’s conclusion that the classification of a relocation as system-related or participant-related is determined on the basis of whether a SASR has been filed by the market participant is not supported by the record. The AESO submitted that its witness, Mr. Sullivan, did not testify that a SASR is the only triggering event that would lead a market participant being charged the cost of a line relocation. Rather, Mr. Sullivan stated that if a SASR is received for a line relocation, the market participant would be held accountable for those costs, in accordance with the current ISO tariff.<sup>1280</sup> Further, Mr. Sullivan confirmed that the purpose of the endorsement letter submitted by the CCA as an aid to cross during the hearing was to endorse only the technical aspects of the line relocation, which is within the scope of what a transmission planner would do.<sup>1281</sup>

1149. In consideration of the foregoing, the AESO submitted that the CCA’s request for a Commission direction for the AESO to produce the guidelines requested by the CCA lacks credibility, and should be disregarded by the Commission.<sup>1282</sup>

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<sup>1274</sup> Exhibit 22942-X0549, CCA argument, paragraph 68.

<sup>1275</sup> Exhibit 22942-X0014.03, PDF page 67, cited at Exhibit 22942-X0549, CCA argument, paragraph 70.

<sup>1276</sup> Transcript Volume 3, page 462 line 11 to page 463 line 3, cited at Exhibit 22942-X0549, CCA argument, paragraph 69.

<sup>1277</sup> Exhibit 22942-X0549, CCA argument, paragraphs 71-72.

<sup>1278</sup> Exhibit 22942-X0572, ATCO Electric reply argument, paragraph 47.

<sup>1279</sup> Exhibit 22942-X0553, ATCO Electric argument, at paragraph 58, PDF page 24, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 177.

<sup>1280</sup> Transcript, Volume 3, page 462, lines 1 to 10, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 173.

<sup>1281</sup> Transcript, Volume 3, page 462, line 11 to page 463, line 3, cited at Exhibit 22942-X0578, AESO reply argument, paragraph 176.

<sup>1282</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 178.

## Commission findings

1150. In its findings in Decision 22742-D01-2019 in respect of the treatment of the costs of relocating transmission line 9L101, the Commission referenced the contribution policy provisions found in Section 8 of the current ISO tariff.<sup>1283</sup>

1151. In addition, the Commission's findings in Decision 22742-D01-2019 referenced findings of the Commission's predecessor in Decision 2003-043 which addressed the question of cost responsibility for the relocation of transmission lines for the purposes of avoiding the sterilization of mineable ore.<sup>1284</sup> The Commission's findings in respect of line relocation cost responsibility in Decision 22741-D01-2019 were related to an application filed by ATCO Electric Ltd. for a Review and Variance of Decision 22742-D01-2019.<sup>1285</sup>

1152. As several aspects of the contribution policy, and especially those related to the classification of costs as between system-related and participant-related elements have undergone significant evolution since 2003, the Commission considers that a review of the 2003 relocation principles is warranted. Accordingly, the AESO is directed to address the reasonableness of the findings made by the Commission's predecessor in respect of the relocation principles discussed at PDF page 18 of Decision 2003-043 as part of its next general tariff application.

### 8.5 Terms and conditions: Construction contributions: Maximum investment levels

1153. AltaLink proposed that the AESO should establish, on a go forward basis, local investment levels by using the prior ten years of actual connection project cost data on a rolling basis with multiplier adjustments that will maintain an average investment coverage of 60 percent. For example, to determine the local investment levels effective 2020, actual project data for the years 2009 to 2018 would be used and the multiplier adjusted to a level that returns the local investment levels that provide an average investment coverage of 60 percent for the 2009 to 2018 projects.<sup>1286</sup>

1154. AltaLink supports the AESO's POD cost multiplier method as filed and takes no issue with average investment coverage of 60 per cent as long as the 60 per cent coverage is established using data representing reasonably contemporary projects. AltaLink found it problematic to use project cost data dating back roughly 30 years.<sup>1287</sup>

1155. AltaLink added that the AESO should continue to use its Investment Levels workbook to determine the local investment levels, and the data and calculations therein should remain intact except that the AESO should limit the project data used to establish the local investment levels to the most recent ten years of actual data. In order to update the local investment levels in future years, a 10-year rolling data set should be used, meaning actual data for new years would be added and data for years going back further than 10 years would be excluded from the calculation.<sup>1288</sup> AltaLink submitted that continued average investment coverage of 60 per cent

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<sup>1283</sup> Decision 22742-D01-2019.

<sup>1284</sup> Decision 2003-043, PDF page 18, paragraph 426.

<sup>1285</sup> Proceeding 22824, Exhibit 22824-X0001.

<sup>1286</sup> Exhibit 22942-X0555, AltaLink final argument, paragraph 252.

<sup>1287</sup> Exhibit 22942-X0555, AltaLink final argument, paragraph 253.

<sup>1288</sup> Exhibit 22942-X0555, AltaLink final argument, paragraph 254.

would ensure that the intended price signal function of the AESO's investment levels remains intact.<sup>1289</sup>

1156. It was further noted by AltaLink that the AESO supported AltaLink's proposal to limit the timeframe of connection projects when applying the POD cost function to determine investment levels. However, the AESO pointed out that in Decision 2014-242 the Commission was not persuaded that longer term data sets should be abandoned to assess investment coverage and the level of multiplier for the 2014 ISO tariff and subsequent updates.<sup>1290</sup>

1157. AltaLink continued by stating that the average investment levels proposed by the AESO in this application would be just 48 per cent if applied to the last five years (2013 to 2018) of project data. AltaLink submitted that this is the same level as that proposed for the 2014 ISO Tariff proceeding and therefore lends credence to AltaLink's 2014 assertion that the higher costs of more recent projects reflect a permanent or sustained structural change.<sup>1291</sup>

1158. In support of its proposal, AltaLink stated that a rolling ten-year dataset:

- doubles the length of the dataset proposed by Devon in 2014
- balances the need to have sufficient data to ensure that one point does not overly influence the entirety of the set and any "investment cliffs" are covered
- removes older project information which is no longer relevant to the cost of current construction
- is sufficiently long to capture a wide representation of projects and economic conditions, and will have a smoothing effect on data variability<sup>1292</sup>

1159. AltaLink countered that the AESO's concern that, if the Commission concluded that a different term for a dataset should be considered, then the AESO would need stakeholder engagement to determine the appropriate timeframe, by noting that this application is being considered by way of a full process which has accommodated extensive opportunity for testing and record development.<sup>1293</sup>

1160. In its evidence Fortis stated it has been unable to identify any systemic or theoretical deficiency in the AESO Customer Contribution Policy that warrants revision at this time. The matter of the sufficiency of TFO investment levels notwithstanding, the AESO Customer Contribution Policy is functioning as originally intended. In consideration of the foregoing, Fortis recommended that if the Commission shares market participants' concerns about the increased frequency and the magnitude of customer contributions that have arisen in recent years, and also shares the concern that TFOs such as AltaLink are not being compensated equitably for the contributed assets which they own, operate and maintain, then these concerns

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<sup>1289</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 257.

<sup>1290</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 258.

<sup>1291</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 261.

<sup>1292</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 262.

<sup>1293</sup> Exhibit 22942-X0555, AltaLink argument, paragraph 263.



are consistent in that they are indications of inadequate transmission investment levels in the ISO tariff.<sup>1294</sup>

1161. Fortis stated that it is of the view that the contribution policy is well-designed and principle-based and the best way to maintain that integrity is to increase transmission investment levels in order to achieve greater alignment with the established AESO Customer Contribution Policy principles.<sup>1295</sup> FortisAlberta further linked the investment levels of TFOs, the customer contribution policy and the POD cost function in its argument to proffer that an increase in investment levels to greater than 60 per cent may address some of AltaLink's concerns.<sup>1296</sup> Fortis recommended:

- A reconsideration of the AESO's prior proposals in its 2012 Customer Contribution Policy to transitionally increase the transmission investment levels to achieve a more reasonable balance in satisfying the contribution policy principles that have been established; and
- A further review of the ISO tariff provisions with respect to the AESO's determination of what constitutes system-related transmission costs (for which a TFO fully invests) versus participant-related costs (whereby a customer contribution may be required).<sup>1297</sup>

1162. In its argument Fortis noted that the AESO, and generally all participants at the time of the AESO 2012 Customer Contribution Policy proceeding, were supportive of raising transmission investment levels from 60 per cent to somewhere between 64 and 76 per cent. The AESO had proposed that the midpoint of 70 per cent be established as the target investment coverage for transmission maximum investment levels. However, the Commission denied the increase. Notwithstanding, Fortis requested in this proceeding that the Commission reconsider the AESO's 2012 Customer Contribution Policy proposal to increase transmission maximum investment levels.<sup>1298</sup>

1163. Fortis noted that the DUC questioned the AESO about utilization of participant-related costs versus investment amounts and the AESO responded that investment is driven by previous tariff derivations of the POD cost curve versus participant-related costs.<sup>1299</sup>

1164. Fortis submitted that changes of the kind required by the AltaLink proposal are sweeping and should not, in any case, be undertaken lightly or in the absence of a complete consultative process.<sup>1300</sup>

1165. In reply, AltaLink submitted that no parties provided argument on its proposal to use a 10-year rolling average dataset and submitted that the Commission should direct the AESO to establish local investment levels going forward by using the last 10 years of actual connection

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<sup>1294</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 131.

<sup>1295</sup> Exhibit 22942-X0559, Fortis argument, paragraph 20.

<sup>1296</sup> Exhibit 22942-X0559, Fortis argument, paragraph 22.

<sup>1297</sup> Exhibit 22942-X0424, Fortis evidence, paragraph 132.

<sup>1298</sup> Exhibit 22942-X0559, Fortis argument, paragraph 24.

<sup>1299</sup> Exhibit 22942-X0559, Fortis argument, paragraph 26.

<sup>1300</sup> Exhibit 22942-X0559, Fortis argument, paragraph 28.

project cost data on a rolling basis along with multiplier adjustments that maintain the average investment coverage of 60 per cent.<sup>1301</sup>

1166. The AESO provided the following response in its rebuttal evidence to the AltaLink proposal:

The AESO supports AltaLink's proposal to limit the timeframe of connection projects when applying the POD cost function to determine investment levels. However, the AESO recognizes that in Decision 2014-242, the Commission stated that it was not persuaded "that it should abandon the use of a longer term dataset to assess investment coverage and the level of the multiplier for the period of time that the 2014 AESO tariff and subsequent updates are in effect."

In the event that the Commission concludes in this Proceeding 22942 that the use of something other than a longer term dataset should be considered, the AESO considers that consultation with stakeholders would be needed to determine the appropriate timeframe as other market participants had similar proposals (of different timeframes) in the 2014 ISO Tariff Application.<sup>1302</sup> [footnotes removed]

### Commission findings

1167. The Commission finds, based on the submissions of the parties, that the investment levels, customer contributions and the POD cost function are inextricably linked. Given the determinations in this decision regarding the POD cost function (Section 4.2), the direction regarding the DUC recommendation number 6 for the cost causation study (Section 4.1) and the Commission's findings regarding customer contributions (sections 8.1-8.5), the Commission finds that any residual issues regarding maximum investment levels should be addressed by parties at the time of the AESO's next tariff application. Further, regarding AltaLink's proposed 10-year rolling average dataset, determinations on datasets were made in the POD cost function section of this decision (Section 4.2). With respect to Fortis's recommendation to increase the AESO investment level above 60 per cent, it is the Commission's view that parties should re-examine their positions on this in light of the Commission determinations regarding customer contribution levels (Section 8) and in light of its findings regarding the Closure Letter (sections 7.1-7.2). Any outstanding concerns on these issues should be brought forward at the time of the AESO's next tariff application.

## 9 Terms and conditions: Administrative revisions and other tariff documents

1168. The AESO provided an overview of its proposed changes to terms and conditions for the 2018 ISO tariff in Section 7 of the amended application. In that section the AESO explained that, at a high level, its proposed changes to its terms and conditions fell into two categories: (i) substantive revisions designed to accommodate new processes or to respond to Commission directives; or (ii) administrative revisions proposed to provide clarity, or to improve consistency with other AESO authoritative documents.<sup>1303</sup>

<sup>1301</sup> Exhibit 22942-X0575, AltaLink reply argument, paragraph 74.

<sup>1302</sup> Exhibit 22942-X0447, AESO rebuttal evidence, paragraphs 47-48.

<sup>1303</sup> Exhibit 22942-X0163, Amended application, paragraph 163.

1169. The AESO explained that while most of the substantive changes to the ISO tariff's terms and conditions related to the AESO's response to the Closure Letter, as addressed in Section 7.1, other notable changes to the terms and conditions and associated documents were as follows:

- Minor modifications to the wording in Section 4 to accommodate the abbreviated needs approval process (ANAP) established under Section 4 of the *Transmission Deficiency Regulation*
- Revisions to system access service agreements
- Revisions to accommodate the market participant choice process established under Section 5 of the *Transmission Deficiency Regulation*
- Revisions to allow distribution direct-connect customers to transact directly with the incumbent TFO rather than indirectly through a DFO

1170. In Table 7-0 of the amended application, reproduced below, the AESO provided a high-level summary of the nature of the changes made to specific sections of its proposed tariff terms and conditions.

**Table 11. Overview of terms and condition changes by section**

Existing terms and conditions section	Proposed change	Type of change
Section 1 – Applicability and Interpretation of ISO Tariff	No change	Minor
Section 2 – Provision of and Limitations to System Access Service	Combines sections 2 and 3 – Provision of System Access Service	Substantive
Section 3 – System Access Service Connection Requirement	Combines sections 2 and 3 – Provision of System Access Service	Substantive
Section 4 – System Access Service Requests	Renumbered to be Section 3 – System Access Service Requests	Substantive
Section 5 – Financial Obligations for Connection Projects	Renumbered to be Section 6 – Financial Obligations for Connection Projects	Substantive
Section 6 – Metering	Removed	-
Section 7 – Provision of Information by Market Participants	Removed	Some provisions moved to new section 2
Section 8 – Construction Contributions for Connection Projects	Renumbered to be Section 4 – Renamed to be - Classification and Allocation of Connection Projects Costs	Substantive
Section 9 – Changes to System Access Service After Energization	Renumbered to be Section 5 – Renamed to be - Changes to System Access Service	Substantive
Section 10 – Generating Unit Owner's Contribution	Renumbered to be Section 7 – Generating Unit Owner's Contribution	Substantive
Section 11 – Ancillary Services	Renumbered to be Section 8 – Ancillary Services	Administrative
Section 12 – Demand Opportunity Service	Renumbered to be Section 9 – Demand Opportunity Service	Administrative
Section 13 – Financial Security, Settlement and Payment Terms	Renumbered to be Section 10 – Renamed to be - Settlement and Payment Terms	Administrative
Section 14 – Peak Metered Demand Waivers	Renumbered to be Section 11 – Peak Metered Demand Waivers	Administrative
Section 15 – Miscellaneous	Renumbered to be Section 12 – Miscellaneous	Substantive

Source: Exhibit 22942-X0163, Amended application, Table 7-0.

1171. In Appendix T to the application, the AESO provided a side-by-side comparison of its proposed tariff terms and conditions against the current tariff terms and conditions.<sup>1304</sup>

### **Commission findings**

1172. The Commission has reviewed the proposed changes to the terms and conditions described in Appendix T to the application, and is satisfied that the majority of the terms and conditions not already discussed in sections 7.1 and 7.2 should be approved as filed. However, the Commission does not accept the AESO's proposal to change the terms and conditions to adopt a proposal by AltaLink and Fortis and described in subsection 7.8.4 of the amended application whereby "transmission direct connected distribution customers," rather than Fortis, would execute a construction commitment agreement directly with AltaLink. In conjunction with this proposal, the AESO outlined certain changes to the wording of certain proposed terms and conditions that would be required to implement this change in Table 7-2 of the amended application.<sup>1305</sup>

1173. The Commission considers that, as Fortis is required to determine its needs for transmission reinforcements, it should have full visibility and control of system access service requests made on behalf of end-use customers served under its tariff. Accordingly, the Commission does not agree with the premise of the proposed changes that the reduction in connection project cycle times warrants the changes proposed. The Commission notes that end-use customers with characteristics necessary to obtain transmission service through a direct connection with a TFO rather than as a transmission direct connected customer of a DFO may obtain the ability to interact directly with the TFO by obtaining an exemption under Section 101(2) of the *Electric Utilities Act*.

1174. In light of the above, the Commission directs the AESO to review all of the proposed changes to its terms and conditions in Table 7-2 and to apply any required amendments necessary to reflect the Commission's finding in this section at the time of its refiling application.

## **10 Other matters**

### **10.1 Other matters: CIP reliability standard cost recovery**

1175. In Decision 3441-D01-2015, the Commission approved Alberta Reliability Standard CIP-002-AB-5.1, bulk electric system (BES) Cyber System Categorization (CIP reliability standard). The CIP reliability standard imposes certain physical and cyber security requirements on Alberta generating units. The CIP reliability standard has three levels low, medium and high. The AESO noted all generators in Alberta have been classified as low impact BES cyber systems except TransAlta's Sundance Plant.<sup>1306</sup>

1176. In Proceeding 3443,<sup>1307</sup> the Commission considered an application from the AESO that requested the Commission's advice and direction on the issue of cost responsibility for

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<sup>1304</sup> Exhibit 22942-X0016.02.

<sup>1305</sup> Exhibit 22942-X0163, Table 7-2, PDF pages 80-83.

<sup>1306</sup> Exhibit 22942-X0163, Amended application, paragraphs 352-354.

<sup>1307</sup> Proceeding 3443: Cost Allocation Critical Infrastructure Protection Alberta Reliability Standards.

compliance with the CIP reliability standard. In its disposition letter,<sup>1308</sup> the Commission directed the AESO to address the issue of cost responsibility for compliance with the CIP reliability standard as part of its next tariff application.

1177. In this application, the AESO determined that the costs of complying with the CIP reliability standard are not recoverable under the ISO tariff. The AESO provided the following rationale:

- The AESO considered that the CIP reliability standard applies to all generators.<sup>1309</sup>
- There are no express legislative or regulatory requirements that impose an obligation on the AESO to pay compensation to generation owners that incur CIP reliability standard costs.<sup>1310</sup>
- Because there would be no system reliability issue if the cost of compliance required a generating unit to be retired, the AESO does not consider that there is a reliability rationale to provide cost recovery.<sup>1311</sup>
- Compliance with CIP reliability standards is a security matter which should be managed by the generator.<sup>1312</sup>
- The AESO considered that it would be fair to apply ISO authoritative documents consistently and equally across all types of market participants.<sup>1313</sup>
- The AESO acknowledged that the imposition of a new reliability standard after a generation developer has made an investment without an understanding of the requirement could be regarded as a barrier to entry. However, the AESO considered the need to ensure system security outweighs this concern.<sup>1314</sup>
- If the market participant is exposed to the cost of compliance, the market participant is incented to make the most economical decisions about how to comply with the standard.<sup>1315</sup>
- The AESO expected that the costs of CIP compliance would eventually be reflected in the energy and ancillary services markets and as such, would eventually be borne by consumers.<sup>1316</sup>
- Requiring the generator to pay is consistent with the historical treatment where generating unit owners have been required to be responsible for changes to reliability standards.<sup>1317</sup>

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<sup>1308</sup> Disposition 3443-D01-2015: Alberta Electric System Operator, Request for a determination of the cost allocation of the Critical Infrastructure Protection Alberta reliability standards, Proceeding 3443, Application 1610884, December 9, 2015.

<sup>1309</sup> Exhibit 22942-X0163, amended application, paragraph 357.

<sup>1310</sup> Exhibit 22942-X0163, amended application, paragraph 359.

<sup>1311</sup> Exhibit 22942-X0163, amended application, paragraph 362.

<sup>1312</sup> Exhibit 22942-X0163, amended application, paragraph 363.

<sup>1313</sup> Exhibit 22942-X0163, amended application, paragraph 363.

<sup>1314</sup> Exhibit 22942-X0163, amended application, paragraph 364.

<sup>1315</sup> Exhibit 22942-X0163, amended application, paragraph 365.

<sup>1316</sup> Exhibit 22942-X0163, amended application, paragraph 366.

<sup>1317</sup> Exhibit 22942-X0163, amended application, paragraph 368.

1178. The AESO submitted that while certain precedent decisions of the Commission were raised by parties in Proceeding 3443 (namely Decision 2008-101 and Decision 2010-60) as examples where the Commission provided recovery to a generator in unique circumstances, these precedents are not comparable to the AESO's proposal that generators should not be able to recover CIP reliability standard costs. The AESO explained that Decision 2008-101, which related to the recovery of costs for the Keephills-Ellerslie-Genesee conversion of unit transformers, is not comparable because it involved a one-time transmission upgrade in respect of a specific generator. In its decision, the Commission did not have to make a finding or develop a general policy for cost recovery for assets that are not part of the transmission system. In Decision 2010-606, which was the approval of Rider J, the AESO's Wind Forecasting Service Cost Recovery, the AESO submitted that Rider J did not establish a precedent because it was more efficient to do the wind forecasting function on behalf of wind generators than to have the generators do it themselves.<sup>1318</sup>

1179. In this application, the AESO requested the Commission provide guidance on how applications for cost recovery for compliance with new ISO rules and reliability standards should be addressed in the future. The AESO suggested that when cost recovery is requested for assets that are not part of the transmission system, a separate application should be filed by either the AESO or the market participant. This application should allow the AESO to participate as an intervener and, where relevant, the findings of such a proceeding should then be included in the AESO's tariff applications.<sup>1319</sup>

1180. TransAlta, Capital Power, and ENMAX took issue with the AESO's proposal on recovery of the costs of compliance of the CIP reliability standard.

1181. TransAlta's Sundance Plant has been classified as a medium impact BES under the CIP reliability standard. TransAlta submitted that in order to comply with the CIP reliability standard it undertook a unit segmented approach, which was significantly less costly than the alternative,<sup>1320</sup> at a cost of approximately \$11.5 million.<sup>1321</sup> TransAlta argued that recovery of its prudently incurred costs for implementing the CIP reliability standard at its Sundance Plant through the AESO tariff is consistent with the AESO's duty to ensure a fair, efficient and openly competitive market, and is consistent with Commission and other North American precedents. TransAlta provided the following rationale:

- Recovery of TransAlta's CIP compliance cost is consistent with applicable legislative and regulatory requirements.
  - No parties have disagreed that CIP cost recovery is a matter within the Commission's jurisdiction and that the Commission is the correct authority to make the determination.<sup>1322</sup>
  - Recovery of the CIP reliability standard compliance costs would be just and reasonable, and not unduly preferential, arbitrary, unjustly discriminatory or inconsistent with or in contravention of the *Electric Utilities Act* or any other law.<sup>1323</sup>

<sup>1318</sup> Exhibit 22942-X0163, amended application, paragraphs 369-372.

<sup>1319</sup> Exhibit 22942-X0163, amended application, paragraphs 377-378.

<sup>1320</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 4.

<sup>1321</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 34.

<sup>1322</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 10.

<sup>1323</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 11-18.

- Commission decisions 2008-101, 23701-D01-2018 and 23165-D01-2018 provide clear precedent for the Commission to provide recovery to a generator in unique circumstances such as this.<sup>1324</sup>
- CIP compliance is part of the safe, reliable and economic operation of the AIES.
  - The compliance work resulted in a system benefit, the implementation of the CIP reliability standards are to the general benefit of the entire AIES not directly to TransAlta.<sup>1325</sup>
  - The CIP reliability standard was approved by the Commission and the changes to TransAlta's facilities were mandatory and outside of its control.<sup>1326</sup>
  - The compliance work at the Sundance Plant was unique and the costs were significant.<sup>1327</sup>
  - TransAlta retained Archer Security Group (Archer) to provide evidence on this matter and Archer recommended cost recovery for prudent and risk-based CIP compliance costs to the Sundance Plant, no one challenged the Archer evidence.<sup>1328</sup>
- Other jurisdictions provide for cost recovery in specific circumstances.
  - The Federal Energy Regulatory Commission has implemented a policy confirming that BES reliability expenditure application will be approved.<sup>1329</sup>
  - A US-Canada Power System Outage Task Force report noted that non-regulated entities would not make expenditures necessary for CIP reliability standards unless they thought they would be profitable.<sup>1330</sup>
- Recovery of TransAlta's CIP compliance cost is consistent with a fair, efficient and openly competitive market.
  - When TransAlta made its capital decision to build the Sundance Plant there was no way that TransAlta could have anticipated the CIP reliability standard requirements or costs.<sup>1331</sup>
  - Imposing new compliance costs on an incumbent market participant that are so significant that they might force the owner of that asset to resize or retire the asset is neither fair, nor efficient, nor openly competitive.<sup>1332</sup>

1182. ENMAX recommended that alternative mechanisms for cost recovery of CIP reliability standard compliance costs be examined by the AESO. ENMAX supports the general principle that the cost of complying with reliability standards, or other delegated legislation under the *Electric Utilities Act*, is a cost of doing business and that those costs should be recovered by market participants through their offer behavior when the same standards apply to all generators or all generators of a certain type (e.g., all coal plants or all wind generators), or when the effect of a standard is broadly applied but not when the costs of complying with a reliability standard are imposed on one market participant or a few of them.<sup>1333</sup>

<sup>1324</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 19-25.

<sup>1325</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 27-30.

<sup>1326</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 31-32.

<sup>1327</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 33-34.

<sup>1328</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 35-37 and Exhibit 22942-X0316.

<sup>1329</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 40.

<sup>1330</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 41.

<sup>1331</sup> Exhibit 22942-X0546, TransAlta argument, paragraphs 52-53.

<sup>1332</sup> Exhibit 22942-X0546, TransAlta argument, paragraph 57.

<sup>1333</sup> Exhibit 22942-X0547, ENMAX argument, paragraphs 26-27.

1183. ENMAX did not support the AESO's claim that generating units on which extraordinary costs are imposed can recover those costs by submitting higher-priced offers. ENMAX submitted that in an attempt to recover the CIP costs, generating units could be priced out of merit and receive no revenue at all. If a generator does succeed in raising the market price of electricity such that it recovers the CIP reliability cost imposed on it, its competitors also receive the higher price, which means the generator is still at a competitive disadvantage.<sup>1334</sup>

1184. Capital Power submitted that the AESO should permit recovery of costs of compliance with the CIP reliability standard through the ISO tariff.<sup>1335</sup> Capital Power argued that the statutory scheme permits the costs of compliance with the CIP reliability standards to be recovered through the ISO tariff and provides the Commission with the authority to direct recovery of these costs and that costs incurred to comply with the CIP reliability standard are properly characterized as incurred as part of meeting the duties and responsibilities of the AESO.<sup>1336</sup> Capital Power also submitted that given the system wide benefits of the CIP reliability standard, it is appropriate for the costs of compliance to be recovered through the ISO tariff.<sup>1337</sup>

1185. Capital Power argued that the AESO's analysis ignored a few key factors. Capital Power submitted that the decision to invest in upgrades to meet the CIP reliability standard is in some cases outside the generating unit owner's control as the AESO has the authority and discretion to designate generating units as low, medium or high risk.<sup>1338</sup> The CIP reliability standard presents a risk to market competitiveness because a generating unit may not be able to recover its fixed costs of complying with the CIP reliability standards through offers in the energy and ancillary services market.<sup>1339</sup> In addition, the CIP reliability standard presents a risk to system reliability and supply adequacy by putting fixed costs on to generating unit owners, which they cannot avoid and may not be able to recover.<sup>1340</sup>

1186. The AESO replied to TransAlta stating that it disagreed that Decision 2008-101 and Decision 23701-D01-2018 are helpful with respect to the recovery of CIP costs because in each of these decisions, the Commission was considering transmission facility costs, which are regulated in Alberta, not generation facility costs, which are unregulated. Further, the AESO submitted that there exist statutory obligations related to the adequacy of the transmission system, whereas, there is no analogous statutory requirement for a generator to ensure that it remains on line providing electricity to a minimum level of service and reliability and the statutory framework suggests that the operational decisions related to generators in Alberta remains with the generator.<sup>1341</sup>

1187. The AESO replied to TransAlta and Capital Power that it did not dispute that compliance with the CIP reliability standards result in a benefit to the system. However, the choice that the generator makes to stay on line and comply with the CIP reliability standards has not been determined to be necessary for the reliability of the system. Additionally, the AESO submitted it would be incorrect to assume that compliance with the CIP reliability standards are the only ISO

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<sup>1334</sup> Exhibit 22942-X0547, ENMAX argument, paragraph 28.

<sup>1335</sup> Exhibit 22942-X0545, CPC argument, paragraph 56.

<sup>1336</sup> Exhibit 22942-X0545, CPC argument, paragraphs 32-36.

<sup>1337</sup> Exhibit 22942-X0545, CPC argument, paragraphs 37-39.

<sup>1338</sup> Exhibit 22942-X0545, CPC argument, paragraphs 41-46.

<sup>1339</sup> Exhibit 22942-X0545, CPC argument, paragraphs 47-52.

<sup>1340</sup> Exhibit 22942-X0545, CPC argument, paragraphs 53-55.

<sup>1341</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 112.



rules or Alberta Reliability Standards that may result in a system benefit and that providing a benefit to system reliability is an overly broad criterion to establish cost recovery for an unregulated asset such as generation.<sup>1342</sup>

1188. With respect to TransAlta's assertion that CIP compliance is mandatory and Capital Power's argument that CIP compliance is outside the generating unit owner's control, the AESO submitted that the generating unit owner has the ability to make operational decisions related to the continued operation of the unit and if CIP compliance would render the generator uneconomic, it would be the owner of the generator who makes the decision whether or not to exit the market.

1189. The AESO submitted that no party rebutted its evidence that CIP compliance costs will be recovered over time and no party has filed evidence demonstrating an anti-competitive outcome related to CIP compliance or that CIP compliance costs would affect the profitability of generators. The AESO noted that the only evidence on the record is that of the AESO, which stated that "[w]hile it is possible that an asset will attempt to recover additional costs through offer behaviour, it is more likely that asset operations at market prices will be sufficient to recover marginal operating costs over time."<sup>1343 1344</sup>

### Commission findings

1190. In Decision 3441-D01-2015, the Commission approved the current CIP reliability standards.

1191. In Decision 2008-101, the Commission examined subsections 122(2) and (3), 121(2), and Section 30 of the *Electric Utilities Act*, and found that it has the authority to approve any costs that are prudently incurred by the AESO, provided that these costs are appropriately incurred as part of the duties and responsibilities of the AESO. The Commission also reviewed Section 29 and subsection 17(h) of the *Electric Utilities Act*, and found that the AESO has responsibilities to provide non-discriminatory system access service to the AIES, to provide a grid robust enough to operate reliably and support competitive markets, and to direct the safe, reliable and economic operation of the AEIS. The Commission continues to agree with the findings in Decision 2008-101 as summarized above.

1192. In Decision 2008-101 and Decision 23701-D01-2018, the Commission declined to develop a general policy regarding costs of assets that are not part of the transmission system and in each decision referred to the unique or specific circumstances<sup>1345</sup> that were before the Commission. In Decision 23165-D01-2018, the Commission approved CIP compliance costs for a regulated utility.<sup>1346</sup>

1193. The AESO noted that Decision 2008-101 and Decision 23701-D01-2018 considered transmission facility costs, which are regulated in Alberta, whereas generation facility costs are not regulated in Alberta.

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<sup>1342</sup> Exhibit 22942-X0578, AESO reply argument, paragraph 113.

<sup>1343</sup> Exhibit 22942-X0257, AESO-AUC-2018NOV01-014(b).

<sup>1344</sup> Exhibit 22942-X0578, AESO reply argument, paragraphs 115-116.

<sup>1345</sup> Decision 2008-101, PDF page 11 and Decision 23701-D01-2018, paragraphs 16 and 17.

<sup>1346</sup> Decision 23165-D01-2018, paragraph 182.

1194. The Commission finds that the *Electric Utilities Act* does not regulate generation facility costs. The Commission agrees with the AESO that there exist no statutory requirements to require a generator to remain on line or provide a specific level of service.

1195. For the reasons discussed below, the Commission is persuaded by the AESO's evidence in this proceeding that TransAlta's costs of complying with the CIP reliability standard should not be recoverable under the ISO tariff. The Commission further finds that the costs for any generator to comply the CIP reliability standard should not be recoverable under the ISO tariff.

1196. The Commission considers that there exist no legislative or regulatory requirements that impose an obligation on the AESO to compensate generation owners for the costs of complying with reliability standards. The Commission finds that generation owners have the opportunity and a mechanism to recover their costs of doing business through their offer behaviours. Further, the Commission finds that, although TransAlta's Sundance Plant was the only generator to be classified as a medium impact BES cyber system, the CIP reliability standard applies to all generators in Alberta and complying with the CIP reliability standard is no different than complying with any other reliability standard and, therefore, the compliance work required at the Sundance Plant was not unique.

1197. For the reasons discussed above, TransAlta's request to recover prudently incurred costs for implementing the CIP reliability standard at its Sundance Plant is denied.

## **10.2 Other matters: Tariff treatment of energy storage installations**

1198. In a ruling dated June 29, 2018,<sup>1347</sup> the Commission determined that energy storage tariff matters could be considered in Proceeding 22942 if interested parties wished to prepare evidence.<sup>1348</sup> Although a few parties filed argument and reply argument regarding energy storage tariff matters, no party filed evidence on this matter.

1199. The AESO noted it had launched an energy storage integration initiative in September 2012 to explore how energy storage facilities can connect to the transmission system and participate in the Alberta electricity market. The AESO provided its recommendation paper resulting from its initiative as Appendix Q<sup>1349</sup> to the application.

1200. In the application, the AESO noted that current legislation supported an energy storage facility being treated as alternating between supplying electricity to the transmission system, similar to a generator, and withdrawing electricity from the transmission system, similar to a load. Therefore, the AESO concluded that would "therefore be charged for location-based cost of losses and comparable charges applicable to generators when supplying electricity (discharging) and would be charged for reasonable costs of the transmission system as applicable to load when withdrawing electricity (charging)."<sup>1350</sup>

1201. In order to better understand the cost causation effects of energy storage facilities, the AESO contracted the University of Calgary to complete an operational and economic dispatch study of energy storage facilities. This study was provided as Appendix O<sup>1351</sup> of the AESO's

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<sup>1347</sup> Exhibit 22942-X0156.

<sup>1348</sup> Exhibit 22942-X0156, paragraph 40.

<sup>1349</sup> Exhibit 22942-X0013.

<sup>1350</sup> Exhibit 22942-X0163, Amended application, paragraph 382.

<sup>1351</sup> Exhibit 22942-X0011.

application. Upon examination of the study, the AESO considered that cost causation supports the application of Rate DTS to energy storage facilities, in hours in which the energy storage facilities are withdrawing electricity from the transmission system, and in hours in which the energy storage facilities are supplying electricity to the transmission system, Rate STS would apply.<sup>1352</sup> This was based on the following observations of the study:

- The cost causation basis for the bulk system charge in Rate DTS is coincident with system peak.
- The cost causation basis for the regional system charge in Rate DTS is load in any hour.
- The cost causation basis for the point of delivery charge in Rate DTS is load in any hour.
- The cost causation basis for the operating reserve charge and the transmission constraint rebalancing charge in Rate DTS is load in the hour in which costs are incurred.
- The voltage control charge in Rate DTS recovers transmission must-run costs as a variable cost through a \$/MWh energy charge. The cost causation basis reflects the variable nature of transmission must-run costs that are affected by many factors.
- The other system support services charge in Rate DTS recovers miscellaneous fixed costs through a \$/MW demand charge. The cost causation basis reflects the fixed nature of those costs.<sup>1353</sup>

1202. The AESO also considered that the application of Rate DTS and Rate STS to energy storage facilities would be similar to their application to dual-use sites and noted that some dual-use sites exhibited similar supply and withdrawal behaviour to the behaviour predicted of energy storage facilities.<sup>1354</sup> The AESO further submitted that energy storage facilities could operate in a manner where they could manage or reduce many of the components of Rate DTS.<sup>1355</sup>

1203. In argument the AESO indicated that it is involved in a few initiatives that include energy storage matters and that it should make progress on these initiative before proposing changes to tariff structures or new rates that may be appropriate for energy storage facilities.<sup>1356</sup>

1204. Capital Power submitted that it supported the AESO's determination of cost causation of energy storage facilities and its determination to apply the existing Rate DTS and Rate STS to energy storage facilities in hours where the facilities draw and supply electricity.<sup>1357</sup>

1205. The CCA took issue with the AESO's proposal and recommended that the AESO consider storage tariff design in terms of costs and benefits of storage from the perspective of transmission, and benefits to the energy and ancillary services market. The CCA argued that energy storage facilities are quite distinct from load or generation and on that basis the treatment of storage as a load under Rate DTS and a supply under Rate STS may not be appropriate for the flexibility, system support and arbitrage services that storage has the potential to provide.<sup>1358</sup>

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<sup>1352</sup> Exhibit 22942-X0163, paragraphs 385-387.

<sup>1353</sup> Exhibit 22942-X0163, paragraph 388.

<sup>1354</sup> Exhibit 22942-X0163, paragraph 390.

<sup>1355</sup> Exhibit 22942-X0163, paragraph 391.

<sup>1356</sup> Exhibit 22942-X0558, paragraphs 185-188.

<sup>1357</sup> Exhibit 22942-X0545, paragraphs 57-60.

<sup>1358</sup> Exhibit 22942-X0549, paragraphs 53-54.

1206. Capital Power replied to the CCA stating that the CCA provided no evidence regarding how the attributes of energy storage facilities justify dissimilar treatment from load and generation. It added that nothing on the record in the current proceeding is sufficient to merit different treatment of energy storage facilities from what the AESO has proposed.<sup>1359</sup>

1207. ENMAX noted in its reply that, as the Commission is planning to explore the impact of technology and innovations such as energy storage in significant detail in the upcoming distribution inquiry, changes to the design of the ISO tariff for energy storage facilities would be premature.<sup>1360</sup> In addition, the AESO submitted in its reply that the Energy Storage Roadmap it is developing for Alberta's electricity system will consider the overall system costs and benefits of storage and therefore should satisfy the CCA's recommendation.<sup>1361</sup>

1208. The Commission notes that ESC did not provide any evidence or argument submissions on this matter despite indicating an interest in this issue in its SIP.<sup>1362</sup>

### **Commission findings**

1209. The Commission has reviewed parties submissions regarding energy storage tariff matters including the AESO's Appendix Q and Appendix O. The Commission notes that no party besides the AESO filed evidence in this proceeding on energy storage tariff related matters and therefore considers the results of Appendix O, the University of Calgary's operational and economic dispatch study of energy storage facilities, to be uncontested.

1210. The Commission finds that the AESO's recommendation that Rate DTS apply to energy storage facilities in hours when they are withdrawing electricity from the transmission system and Rate STS in hours when they are supplying electricity to the transmission system is reasonable and is supported by current legislation, cost causation, the similarity to behaviour of some dual-use sites and the results of the University of Calgary's study.

1211. The AESO noted that it is currently involved in a number of initiatives including energy storage matters<sup>1363</sup> and submitted that progress needs to be made on these initiatives before tariff structures or new rates for energy storage facilities are proposed by the AESO. The Commission agrees with the AESO and finds that changes to the design of the ISO tariff for energy storage facilities would be premature until after these initiatives have been completed and the AESO submits for an approval of a revised ISO tariff with its proposals to the Commission. The AESO's proposed 2018 ISO tariff in this application for energy storage facilities is approved as filed.

### **10.3 Other matters: Future ISO tariff development/consideration in other proceedings**

1212. In its ruling of June 29, 2018, the Commission directed the AESO to file its next comprehensive tariff application before the end of the first quarter of 2020.<sup>1364</sup> However, as the Commission has made several directions in this decision that were not contemplated in the June

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<sup>1359</sup> Exhibit 22942-X0565, paragraph 28.

<sup>1360</sup> Exhibit 22942-X0571, paragraph 31.

<sup>1361</sup> Exhibit 22942-X0578, paragraph 135.

<sup>1362</sup> Exhibit 22942-X0558.

<sup>1363</sup> Commission Distribution System Inquiry, Energy Storage Roadmap.

<sup>1364</sup> Exhibit 22942-X0156, paragraph 67.

2018 ruling, the Commission is concerned that the original deadline for the AESO to file its next GTA may not be achievable.

1213. Given the foregoing, the Commission directs the AESO to assess its ability to prepare a comprehensive tariff application before the end of the first quarter of 2020 in light of the findings and directions in this decision. If the AESO considers that the existing deadline is not achievable, the Commission directs the AESO to so advise and propose an alternate deadline in its compliance filing pursuant to this decision.

#### 10.4 Other matters: Directive compliance

1214. In Table 9-1 of the amended application, the AESO provided the following summary of its responses to directions from prior decisions related to the proposed ISO tariff:

**Table 12. Directions responded to in amended 2018 ISO tariff application**

Directive	Description	AESO response
Decision 2014-242 directive 1 (paragraph 208)  Exclusion of customer-owned projects	The proposal of the DUC is denied. The AESO is directed to continue to exclude customer-owned projects from the database and POD cost calculations (paragraph 208).	Addressed in section 4.3.1 of the amended application
Decision 2014-242 directive 2 (paragraph 260)  Update on directive 2 implementation	The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database (paragraph 260).	Addressed in section 4.3 of the amended application.
Decision 3473-D01-2015 directive at paragraph 31	The Commission has reviewed the AESO's response to Direction 2 and finds that it has resulted in unanticipated effects that could not have been known at the time of proceeding 2718. The AESO's proposal to delay the implementation of Direction 2 until the matter can be thoroughly explored is reasonable and both the UCA and Devon agree with this approach (paragraph 31).	Addressed in section 4.3 of the amended application.
Decision 2014-242 directive 4 (paragraph 422)  Long-term transmission rate projections	The Commission finds the AESO's current practice to be helpful and the AESO is therefore directed to continue its current practice of providing its long-term transmission rate projections (paragraph 422).	Addressed in section 5.7 of the amended application.
Decision 2014-242 directive 10 (paragraph 704)  Rider C design	The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C	Addressed in section 6.1 of the amended application.

Directive	Description	AESO response
	design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA (paragraph 704).	
Disposition 3443-D01-2015 (Proceeding 3443 disposition letter, paragraph 6)  CIP Alberta reliability standard compliance costs	The AESO is directed to address as part of its next general tariff application, the issue of cost responsibility for compliance with the CIP Alberta reliability standards. The AESO's application must either state that the AESO is including any such costs in its proposed tariff as recoverable under the AESO's tariff pursuant to section 30(2)(a)(iv) of the Electric Utilities Act, or that the AESO does not propose that some or all of such costs are recoverable through its proposed tariff. The AESO must provide the rationale for its position. In this way, if the AESO does not propose that such costs are recoverable through its proposed tariff, any directly affected party may register to participate in the proceeding and advance its position, stating its bases for and quantifying its claim to recover them.	Addressed in section 8.1 of the amended application
Decision 21735-D02-2016 directive 1 (paragraph 108)  Stakeholder consultation regarding DAR methodology and Rider C	In its letter issued on September 19, 2016, the Commission determined that the issues raised by the PS Group had the potential to materially affect the current proceeding as well as past and future deferral account reconciliation proceedings. However, for the reasons set out in this decision, the Commission has approved the AESO's application and has not granted the relief requested by the PS Group. Nonetheless, the Commission expects the AESO to follow through on its commitment to further consult with stakeholders on this issue and directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application (paragraph 108).	Addressed in section 6.1 of the amended application

Source: Exhibit 22942-X0163, Amended application, Table 9-1

## Commission findings

1215. The Commission is satisfied that the summary of Commission directions to be addressed as part of the 2018 ISO tariff application is complete. The Commission further agrees that the cross-references that the AESO has provided to sections of its amended application are accurate.

Given the foregoing, the Commission approves the AESO's compliance with directives included in the Table 9-1 summary, as filed.

## 11 Order

1216. It is hereby ordered that:

- (1) The AESO shall refile its 2018 ISO Tariff Application to reflect the findings, conclusions and directions in this decision after January 1, 2020 but no later than January 31, 2020.

Dated on September 22, 2019.

### Alberta Utilities Commission

*(original signed by)*

Mark Kolesar  
Chair

*(original signed by)*

Henry van Egteren  
Vice-Chair

*(original signed b)*

Tracee Collins  
Commission Member

**Appendix 1 – Proceeding participants**

<b>Name of organization (abbreviation) Company name of counsel or representative</b>
Independent System Operator (ISO or AESO) Stikeman Elliott LLP
Access Pipeline Inc.
Alberta Direct Connect Consumers Association (ADC) Ackroyd LLP
Alberta Solar Cooperative
AltaGas Ltd. (AltaGas)
AltaLink Management Ltd. (AltaLink) Borden, Ladner Gervais LLP
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
ATCO Power Canada Ltd. (ATCO Power)
Aura Power Renewables Ltd.
Balancing Pool
BluEarth Renewables Inc. Blake, Cassels & Graydon LLP
BowMont Capital and Advisory Ltd.
Bullfrog Power Inc.
Canada West Ski Areas Association
Canadian Solar Industries Association (CanSia) Osler, Hoskin & Harcourt LLP



<b>Name of organization (abbreviation) Company name of counsel or representative</b>
Canadian Geothermal Energy Association
Canadian Wind Energy Association
Capital Power Corporation (CPC) Borden Ladner Gervais LLP
Cenovus FCCL Ltd. (Cenovus)
C&B Alberta Solar Development
The Cities of Lethbridge and Red Deer Chymko Consulting Ltd.
Consumers' Coalition of Alberta (CCA)
City of Medicine Hat
Decentralised Energy Canada
Devon Canada (Devon) Edmond de Palezieux
Direct Energy Marketing Limited
Distributed Generation Working Group (DGWG)
Dual Use Customers (DUC)
Energy Storage Canada (ESC) Travis Lusney
ENMAX Energy Corporation (ENMAX Energy)
ENMAX Power Corporation (ENMAX Power)

<b>Name of organization (abbreviation) Company name of counsel or representative</b>
EPCOR Distribution & Transmission Inc. (EDTI) Borden Ladner Gervais LLP
First Nations Power Authority
FortisAlberta Inc. (Fortis) Osler, Hoskin & Harcourt LLP
Green Cat Renewables Canada Corporation
Greengate Power Corporation (Greengate)
Horseshoe Power GP Ltd.
Industrial Power Consumers Association of Alberta (IPCAA)
Keepers of the Athabasca Watershed Society
Kinder Morgan Canada Edmond de Palezieux
Lionstooth Energy
Louis Bull Tribe
Métis Nation of Alberta
Neyaskweyak Group of Companies (NGCI)
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
Solar Krafte Utilities Inc. (Solar Krafte)
Skyfire Energy Inc.

<b>Name of organization (abbreviation)</b> <b>Company name of counsel or representative</b>
Solar Power Investment Cooperative of Edmonton (SPICE)
Southern Alberta Alternative Energy Partnership Randolph Seibold
Suncor Energy Inc. (Suncor)
TransAlta Corporation (TransAlta)
TransCanada Energy Ltd. (TCE) Fasken Martineau DuMoulin LLP
Turning Point Generation (TPG)

Alberta Utilities Commission
Commission panel
M. Kolesar, Chair
H. van Egteren, Vice-Chair
T. Collins, Commission Member
Commission staff
C. Wall (Commission counsel)
S. Sajnovics (Commission counsel)
J. Halls
S. Karim
C. Strasser
D. Ward
D. Ryan
W. MacKenzie
H. Gnenz

**Appendix 2 – Oral hearing – registered appearances**

<b>Name of organization (abbreviation) Name of counsel or representative</b>	<b>Witnesses</b>
Alberta Electric System Operator (AESO) K. Miller S. Graham T. Sloan	D. Sullivan L. Papworth R. Sharma L. Kerr J. Martin
Access Pipeline Inc. (Access Pipeline) T. Kruger E. de Palezieux J. Dawson	
AltaLink Management Ltd. (AltaLink) R. Block, QC K. Salmon	R. Senko G. Hart J. Piotto
ATCO Electric Ltd. (ATCO Electric) L. Keough	N. Palladino L. Shaben A. Nassif
Capital Power Corporation (CPC) A. Ross D. Johnson C. Robb B. Morgan	
Community Generation Working Group (CGWG) M. Ignasiak C. Richards	C. Runge P. Bateman D. Hildebrand J. Peters
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC	R. Retnanandan
Distributed Generation Working Group (DGWG) T. Whiteside	T. Whiteside
Dual Use Customers, Alberta Direct Connect Consumers Association, and Industrial Power Consumers Association of Alberta (DUC et. al.) Richard Secord	D. Hildebrand
EPCOR Distribution & Transmission Inc. (EDTI) Jonathan Liteplo	
FortisAlberta Inc. (Fortis) M. Ignasiak C. Richards	J. Sullivan M. Stroh C. Eck
Solar Krafte Utilities Inc. (Solar Krafte) J. Pigeon	
TransAlta Corporation (TransAlta) B. Hunter	

### Appendix 3 – Summary of Commission directions

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

1. The Commission accepts the AESO's 2018 study provided in the AESO's amended application for 2018. However, the Commission directs the AESO to continue the consultation process with respect to the 12 CP issue, the regional tariff design and the bulk tariff design and to investigate and apply, if appropriate, the DUC's recommendations 1, 5 and 6 in its consultative process. .... paragraph 74
2. The Commission directs the AESO to conduct a thorough investigation of alternative approaches using installed capacity, although contract capacity also may play a role for upgrade projects. This should, at a minimum, comprise the following:
  - (1) No further consideration of using contract capacity as the explanatory variable for the POD costs associated with greenfield projects;
  - (2) Investigation of separate POD regressions for greenfield and upgrade projects, or for a single regression that incorporates different explanatory variables for the two types; for example, by including previous MW as an explanatory variable, where previous MW would equal zero for greenfield projects, or by utilizing various qualitative (dummy) variables that are equal to one for upgrade projects but equal to zero for greenfield projects (or vice-versa), included in the regression either or both additively and multiplicatively;
  - (3) No further consideration of including zero MW upgrade projects in the analysis unless and until the specification is modified to allow costs to depend on some relevant explanatory variable in addition to MW, or possibly an intercept;
  - (4) Investigation of the use of an alternative functional form that allows for the possibility of an intercept; if such an alternative does not prove to be useful, dropping the fiction of an intercept for a power function that does not have one;
  - (5) Investigation of a specification that, like Option #6, uses a data set where all the projects for a particular substation are considered together;
  - (6) Evaluation criteria for different POD cost function specifications that do not focus on the price signals that are sent, but rather focus on the specification itself; as emphasized throughout the preceding Commission findings, no useful information about cost causation can flow from an incorrect POD cost function specification;
  - (7) No further consideration of the iterative process concerning upgrade projects for which the greenfield costs are unknown; as explained above, this process modifies the relationship between known costs and MW for greenfield projects without having any information that can contribute to this relationship;
  - (8) Using criteria to evaluate alternative specifications or approaches that recognize that specifications with different datasets cannot be compared on the basis of R-squared, and where omission or inclusion of data points is based on defensible criteria concerning the function specification rather than the price signals that are sent or objectives concerning recognizing participant behaviour;

- (9) Notwithstanding the AESO's stated objective to maximize the number of projects in the database, evaluation of the value of continuing to include the pre-AESO projects, considering their age and the extent of inflation adjustments that they require, in terms of their contribution to the range of projects included in the analysis and the empirical implications of their inclusion or omission; and
- (10) Consideration of alternative methods that can be used to convert information from a POD cost function estimated using installed capacity to one where rates are based on contract capacity, in such a way that this conversion or translation does not involve adjustment by a constant ratio and results in a function that is not just a scaling of the Option #1 results.
- ..... paragraph 202
3. Given these concerns, the AESO's proposed change to the existing power factor deficiency charge to \$1,200 per MVA from \$400 per MVA is denied. The Commission agrees with the AESO that an increase to the charge is required, but the Commission has not been persuaded by the AESO that an increase to \$1,200 per MVA is the appropriate amount. Considering this finding, the AESO's proposal to index the power factor deficiency charge to the weighted average increase in transmission system costs is also denied. The AESO is directed to either provide further support for its calculation of the \$1,200 per MVA charge in the compliance filing to this decision or in its next comprehensive GTA. .... paragraph 254
4. Accordingly, the AESO is directed in its next comprehensive GTA to provide a discussion of possible revised rate design structures for billing capacity and to discuss if the use of reactive power was considered in the revised rate design structures. .... paragraph 258
5. The Commission directs the AESO to continue including this type of analysis in its future comprehensive GTAs. .... paragraph 265
6. For all of the above reasons, the AESO's request that Rider A1 be extended for an additional 20 years to 2041 is denied. The AESO is directed to update its proposed 2018 ISO tariff to reflect this finding in its refiling. .... paragraph 313
7. The Commission approves the AESO's proposed method to calculate the GUOC rate, and the AESO's GUOC rates, included in Table 10 above. However, in its refiling to this decision, the Commission directs the AESO to clarify whether part (b) of the capacity used to calculate a GUOC is still required, given the Commission's decision with respect to the E.L. Smith Solar Power Plant (Decision 23418-D01-2019). .... paragraph 323
8. The Commission directs the AESO to amend subsection 5.2(2) to include wording that this subsection will not apply to deviations below 10 per cent, that any proposed adjustments by the AESO must first be discussed with the market participant, and that a direct reference to the sections of the dispute resolution process that can be utilized by market participants regarding any disputes that may arise under this provision of the terms and conditions be provided. .... paragraph 416
9. To clarify, the Commission is not looking for detailed rules regarding the application of this subsection. Rather, if following stakeholder engagement, further amendments to subsection 5.2(2) are determined to be beneficial and consensus can be made in an information document, then the AESO is directed to include those amendments in the information document as part of its next AESO tariff application. .... paragraph 418

10. Although the Commission considers that the AESO should have discretion with respect to subsection 3.4(1) and that the AESO will exercise its discretion reasonably, in light of the concerns of parties in this proceeding, additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.4(1). Accordingly, the Commission directs the AESO to work with market participants for the purposes of addressing any concerns arising from the application of this subsection and any changes proposed in response to those concerns at the time of the next comprehensive ISO tariff application. .... paragraph 442
11. As with the Commission’s direction in Section 7.2.2 additional review of the provision may be of value once the AESO has had an opportunity to apply subsection 3.2(2). Accordingly, the Commission directs the AESO to work with market participants for the purposes of addressing any concerns arising from the application of this subsection and any changes proposed in response to those concerns at the time of the next ISO tariff application. .... paragraph 462
12. The Commission agrees with EDTI that by excluding the phrase, “including the determination of costs to be system-related in certain circumstances that might, under strict application of the customer contribution provisions, have been classified as participant-related,” the AESO’s proposed subsection 4.10 may not provide adequate discretion to the AESO to vary the application of certain aspects of its tariff contribution policy when circumstances warrant. Accordingly, the Commission directs the AESO to revise its proposed subsection 4.10 at the time of its refiling application to substantially replicate the wording in the current tariff’s subsection 8.10. .... paragraph 525
13. The Commission directs the AESO to work with the DFOs to develop an objective set of criteria for the initiation of system transmission projects reflecting the Commission’s findings in this decision. .... paragraph 607
14. The AESO is directed to provide a report on the status of such discussions, including a discussion of any criteria the AESO would propose for determining “grey area” system projects at the time of its next comprehensive GTA. The AESO’s proposed changes to its tariff approved in this decision are not suspended pending the development of this criteria. .... paragraph 608
15. The Commission, as an expert tribunal, employs a rigorous procedural process in its determination of applications before it. In doing so, it also recognizes that tribunals are created to increase the efficiency of the administration of justice. Therefore, in order to consider this matter expeditiously, notwithstanding the usual scope associated with a compliance filing, the Commission directs the AESO to provide a complete explanation of its understanding of the effect on the U of A of its adjusted metering practice at the time of its refiling application. The U of A will be permitted to file evidence in this refiling application in response to the AESO’s filing. .... paragraph 843
16. In its compliance filing the AESO is directed to file any changes that are necessary to the ISO tariff to comply with the Commission’s findings in this section..... paragraph 873
17. Because the AESO’s revised position on this issue was brought forward in argument, the Commission does not have enough information to make determinations with respect to other exemptions or approvals for dual-use customers or industrial complexes. If there are other issues regarding the metering of industrial complexes and specific exemptions or approvals available to industrial complexes, the AESO is directed to identify these

- and, if necessary, propose and justify amendments to its tariff in its compliance filing. .... paragraph 874
18. Accordingly, the Commission directs the AESO, in its refile, to consult with AltaLink and for the AESO and AltaLink to provide a joint proposal for the implementation of AltaLink’s contribution proposal. .... paragraph 1079
19. In light of the foregoing, the Commission would like to examine whether a return to the use of the AESO standard service definition, rather than the standard of facilities in excess of GEIP, should be used to determine optional facility costs. Accordingly, the Commission directs the AESO to address the Commission’s findings in its next comprehensive ISO tariff application. .... paragraph 1139
20. As several aspects of the contribution policy, and especially those related to the classification of costs as between system-related and participant-related elements have undergone significant evolution since 2003, the Commission considers that a review of the 2003 relocation principles is warranted. Accordingly, the AESO is directed to address the reasonableness of the findings made by the Commission’s predecessor in respect of the relocation principles discussed at PDF page 18 of Decision 2003-043 as part of its next general tariff application. .... paragraph 1152
21. In light of the above, the Commission directs the AESO to review all of the proposed changes to its terms and conditions in Table 7-2 and to apply any required amendments necessary to reflect the Commission’s finding in this section at the time of its refile application. .... paragraph 1174
22. Given the foregoing, the Commission directs the AESO to assess its ability to prepare a comprehensive tariff application before the end of the first quarter of 2020 in light of the findings and directions in this decision. If the AESO considers that the existing deadline is not achievable, the Commission directs the AESO to so advise and propose an alternate deadline in its compliance filing pursuant to this decision. .... paragraph 1213



**Appendix 4 – Abbreviations**

Abbreviation	Name in full
ANAP	abbreviated needs approval process
CIAC	contribution in aid of construction
CIP	critical infrastructure protection
DAT	duplication avoidance tariff
DFO	distribution facility owner
DTS	demand transmission service
EPRI	Electric Power Research Institute
GEIP	good electric industry practice
GUOC	generating unit owner's contribution
kV	kilovolt
MVA	megavolt ampere
MW	megawatt
NID	needs identification document
NPV	net present value
PBR	performance-based regulation
PILON	payment in lieu of notice
RCN	replacement cost new
RCN-D	replacement cost new-depreciation
REA	rural electrification association
REP	renewable electricity program
SAS	system access service
SASR	system access service request
STS	supply transmission service
TFO	transmission facility owner