



# **Alberta Electric System Operator**

**2007 General Tariff Application**

**December 21, 2007**

**ALBERTA ENERGY AND UTILITIES BOARD**

Decision 2007-106: Alberta Electric System Operator  
2007 General Tariff Application  
Application No. 1485517

December 21, 2007

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# **ALBERTA ENERGY AND UTILITIES BOARD**

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**Calgary Alberta**

## **ALBERTA ELECTRIC SYSTEM OPERATOR GENERAL TARIFF APPLICATION FOR THE PERIOD JANUARY 1, 2007 TO DECEMBER 31, 2007**

**Decision 2007-106  
Application No. 1485517**

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### **1 INTRODUCTION**

On November 3, 2006, the Alberta Electric System Operator (AESO) filed a Phase I and Phase II General Tariff Application (GTA) requesting approval of its 2007 forecast revenue requirement amounts for wire costs, ancillary services, transmission line losses, and AESO own costs for 2007 rate setting purposes. The AESO also requested approval of both new rate schedules and changes to the terms and conditions of providing system access service.

The Application requested the following:

- 1) Approval of the AESO's 2007 forecast revenue requirement amounts for wire costs, ancillary services, transmission line losses, and AESO own costs for 2007 rate setting purposes;
- 2) Confirmation from the Board that the AESO's entire 2007 forecast revenue requirement is subject to deferral account treatment;
- 3) Approval of the proposed tariff, effective April 1, 2007, including new rate schedules and changes to the terms and conditions (T&Cs) of providing system access service, including changes to the Customer Contribution Policy set forth in Article 9 of the T&Cs and the DTS Rate;
- 4) Confirmation from the Board permitting the AESO to continue to employ its existing rate Riders B and C and annual deferral account reconciliation process to calculate rates and recover actual incurred costs (excluding losses) until such time as the Board approves changes to those processes; and
- 5) Confirmation from the Board of its acceptance of the AESO's responses to outstanding matters.

The AESO also requested permission to engage in a negotiated settlement process (NSP) to conduct further discussions with stakeholders in an attempt to limit or reduce the number of issues to be decided by the Board.

On November 15, 2006, a Notice of Application (Notice) in respect of the Application was transmitted electronically to interested parties who had participated in the AESO's 2006 general tariff proceeding. The Notice was also published in the Calgary Herald and the Edmonton Journal on November 20, 2006.

Further to instructions set out in the Notice, on December 4, 2006, the AESO advised the Board that it did not intend to pursue the NSP further.

By letter dated May 3, 2007, the Dual-use Customers (DUC) and TransCanada Energy Ltd. (TCE) made a motion pursuant to section 9 of the Board's Rules of Practice<sup>1</sup> (Rules of Practice). The motion requested an order of the Board directing the AESO to make available the supporting data relied upon by the AESO in preparing certain figures and related observations in the AESO's rebuttal evidence.

The Board invited comments from the AESO and extended DUC/TCE an opportunity to reply to the AESO's comments. The AESO responded to this motion by letter dated May 7, 2007. Its response included a request for confidentiality of customer hourly load data, if the Board granted the motion. DUC/TCE replied to the AESO response by letter dated May 8, 2007. In a letter dated May 9, 2007, and subject to certain confidentiality restrictions, the Board granted this motion and ordered that the AESO make available the supporting data. The request for confidentiality was granted, and certain procedures set forth in the Board's May 9, 2007 letter were implemented to protect the confidentiality of the information.

On April 11, 2007 the Provincial Government enacted an amended *Transmission Regulation*<sup>2</sup> (the 2007 *Transmission Regulation*), which replaced the previous the previous *Transmission Regulation*<sup>3</sup> (the 2004 *Transmission Regulation*).

The Application was heard by way of an oral hearing held at the Board's hearing room in Calgary, Alberta. The oral hearing commenced May 14, 2007 and was adjourned on May 29, 2007. The panel hearing the Application was comprised of Mr. T. McGee as Presiding Member, and Mr. D. Larder, Q.C., and Ms. L. J. Bayda as Acting Members. Written argument was received from the parties on or about June 22, 2007 and written reply was received on July 13, 2007.

Participants in the oral hearing were reminded by Presiding Member that proposed revisions to Article 11 (formerly Article 24) of the AESO tariff were already before the Board as part of application number 1357161 (the Article 11 Proceeding). Accordingly, parties were advised that matters related to Article 11 of the AESO tariff would be dealt with in that proceeding and not in the proceeding to consider the Application.

On July 19, 2007, the Board set out a schedule to receive submissions pursuant to another motion filed with the reply argument of DUC/TCE on July 13, 2007 (the DUC/TCE Motion), requesting that a portion of the AESO's argument concerning the standby rate on the grounds that it constituted new evidence. Board correspondence issued August 15, 2007 acknowledged the receipt of submissions on the DUC/TCE Motion, concluding with the receipt of reply submission from DUC/TCE received on July 31, 2007. The standby rate proposed by DUC/TCE and the DUC/TCE Motion is considered in section 5.11 of this Decision.

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<sup>1</sup> Alberta Regulation 101/2001, as amended

<sup>2</sup> Alberta Regulation 86/2007, as amended

<sup>3</sup> Alberta Regulation 174/2004

By letter dated October 25, 2007, the Board informed interested parties of the approach it was considering with respect to the construct of the POD cost function, and provided parties with an opportunity to consider or provide comments on the POD cost function under consideration. This step was taken to ensure that all parties had an opportunity to comment on a POD cost function that had not specifically been addressed during the proceeding. Comments were received on November 5, 2007, a Board information request was issued on November 15, 2007, and reply comments were received on November 26, 2007. The POD cost function is considered in section 5.7 of this Decision.

The Board therefore considers the record of this proceeding to have closed on November 26, 2007.

The Board has reviewed the evidence, argument, reply argument, POD comments and reply comments related to each of the issues from parties to this proceeding. Any references to specific parts of the record are intended to assist the reader in understanding the Board's decision, but should not be taken as an indication that the Board did not consider the entire record as it relates to that issue.

As is further described in section 9.1 of this Decision, in order to assist parties in cross referencing outstanding directions arising from Decision 2005-096<sup>4</sup> and other relevant AESO decisions, the Board has, for the purposes of this Decision, adopted the numbering scheme used by the AESO in Application 1420890. The matrix reflecting this numbering scheme is reproduced as Appendix 5 to this Decision.

## 2 LEGISLATIVE REQUIREMENTS

In the Application, the AESO cited specific requirements of the 2004 *Transmission Regulation* regarding the recovery of transmission system costs from its customers, and identified how it had responded to these requirements:

In accordance with section 30 of the *Transmission Regulation*, the AESO has allocated all costs of the transmission system (except for losses and regulated generating unit (RGU) connection costs) to load customers and exporters. The RGU connection costs continue to be allocated to regulated generators "to place existing generation on the same competitive basis as new generation," as directed in EUB Decision 2000-1 concerning the ESBI Alberta Ltd. 1999/2000 General Rate Application Phase 1 and Phase 2.

In accordance with section 22, the cost of transmission system losses is allocated to generators, import service, and opportunity services. Calibration Factor Rider E also applies to those services as required by section 21(1).

The allocation of costs to load and supply customers is summarized in Schedule 5.1, and the related allocation of tariff revenue offsets is summarized in Schedule 5.2 in section 5 of this Application.

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<sup>4</sup> Decision 2005-096 – Alberta Electric System Operator (AESO) 2005/2006 General Tariff Application (Application No. 1363012) (Released: August 28, 2005)

Finally, in accordance with section 15(6), export and import rates are proposed for users of “merchant” transmission facilities.<sup>5</sup>

The above provisions of the 2004 *Transmission Regulation* that were in effect at that time read as follows:

**Transmission projects providing interconnection capacity with other jurisdictions**

15(6) The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the facilities referred to in this section for import or export of electricity to or from Alberta.

**Adjustment of loss factors**

21(1) In accordance with the rules, loss factors may be adjusted by a calibration factor to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis.

**Recovery of transmission losses**

22(1) In accordance with the ISO tariff and the loss factors determined under this Part,

- (a) the owner of a generating unit must pay location-based loss charges or receive credits;
- (b) importers of electric energy under a firm service arrangement must pay location-based loss charges or receive credits.

(2) A person receiving transmission service under an interruptible service arrangement for load, import or export must pay location based loss charges that recover the full cost of losses required to provide this service.

**ISO tariff - transmission system considerations**

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

- (a) ensure
  - (i) the just and reasonable costs of the transmission system are wholly charged to owners of electric distribution systems, 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 an owner of an electric distribution system is recoverable in the tariff of the owner of the electric distribution system;
- (b) ensure owners of generating units are charged local interconnection costs to connect their generating unit to the transmission system, and are charged a financial contribution towards transmission system upgrades and for location-based cost of losses;
- (c) consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.

In light of the amendments made to the *Transmission Regulation* after the AESO had submitted the Application, the AESO stated in argument that it had devised its proposed XTS and MTS rates to comply with the 2007 *Transmission Regulation*:

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<sup>5</sup> Ex. 005, Application, Section 4, pp. 3-4

When the AESO's 2007 Application was prepared and filed, the 2004 Transmission Regulation (AR 174/2004) required certain arrangements regarding the recovery of transmission system costs from customers of the AESO. Specifically, sections 15(6), 21(1), 22(1) and (2), and 30 provided specific requirements relating to the AESO's tariff with respect to merchant interconnections, losses calibration factor, recovery of losses, and tariff cost recovery, respectively.

The tariff as filed complied with all provisions of the 2004 Transmission Regulation, and no party contested the AESO's compliance with the tariff-related requirements of the 2004 Transmission Regulation.

As noted in Section 1 above, the 2007 Transmission Regulation (AR 86/2007) was enacted on April 11, 2007, just over a month before the beginning of the oral hearing of the AESO's 2007 Application. The 2007 Transmission Regulation generally retained the tariff related provisions of the 2004 Regulation which it replaced, with the exception of changes to the services to which loss and calibration factors applied for the recovery of the cost of transmission line losses. Whereas subsections 22(1) and (2) of the 2004 Transmission Regulation required the AESO to recover the cost of transmission line losses from generating units, importers, and opportunity services, clause 31(1)(a) of the 2007 Transmission Regulation added exporters to this list (effective January 1, 2009 per section 36). Loss factors continue to be established through ISO Rules under the 2007 Transmission Regulation.

In anticipation of the loss factor changes in the 2007 Transmission Regulation, the AESO included application of a loss factor (determined under the ISO Rules) in its proposed Export Transmission Service Rate XTS and Merchant Transmission Service Rate MTS. In its evidence (page 36, lines 6-21), TransCanada opposed the inclusion of a loss factor in these rates in advance of enactment of the revised Transmission Regulation. As the 2007 Transmission Regulation is now in force and establishes that non-opportunity export services will not pay for losses prior to January 1, 2009, the AESO submits that TransCanada's concern has been addressed. The losses charge in Rates XTS and MTS should be approved as filed, and the loss factor for these rates will be set at 0% under the ISO Rules until December 31, 2008, in accordance with the 2007 Transmission Regulation.

In any event, the AESO notes that its charges must comply with requirements of applicable legislation, in the event of conflict with any provisions that may exist in the approved tariff.<sup>6</sup>

No parties took issue with the AESO's summary of the changes to these provisions, as indicated above. The Board has reviewed these provisions as they appeared in both the 2004 *Transmission Regulation*, and the 2007 *Transmission Regulation*,<sup>7</sup> and generally agrees with the AESO's summary above of the changes.

The AESO stated that no parties (other than ADC) had taken issue with the AESO's compliance with the applicable legislation and submitted that its proposed tariff appropriately meets all relevant legislative requirements. The AESO did note that it intends to include in its next GTA two aspects of the 2007 *Transmission Regulation*, system contribution refund period (subsection

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<sup>6</sup> AESO Argument, p. 6

<sup>7</sup> *Transmission Regulation* (AR 86/2007), subsections 27(6), 33(1), 34, 35 and 47

29(4)), and exemption of generators less than 1MW from making a system contribution (section 30).

With respect to the requirement that the tariff provide for a system contribution refund as required by subsection 29(4) of the 2007 *Transmission Regulation*, the AESO pointed out in argument that its proposed tariff retains Article 9.12(b) from the 2006 tariff, which provides for the refund of the system contribution “within a maximum of 10 calendar years following the date it was paid,” as was required by the 2004 *Transmission Regulation*. Section 29(4) of the 2007 *Transmission Regulation* requires the system contribution paid by owners of generating units to be refunded “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.” The AESO noted that the system contribution is paid before a generating unit begins to operate, generally at least one to two years earlier. Under the AESO’s proposed tariff, the system contribution would therefore typically be refunded within eight or nine years of the date of operation. The AESO submitted that its proposed tariff is technically in compliance with the requirements of subsection 29(4) of the 2007 *Transmission Regulation*, but recognized that it does not necessarily reflect the intent that the refund occur over a period of not more than 10 years.<sup>8</sup>

Section 30 of the 2007 *Transmission Regulation* exempts generating units with capacity of one MW or less from the system contribution payment and refund provisions. The AESO indicated in argument that its proposed tariff would retain the provisions of its current tariff which does not provide for such an exemption. It also indicated that interconnections to the transmission system of generators with capacity of 1 MW or less are very rare, and that no generators of that size were in the AESO’s application queue at that time. It further indicated that if a one MW or smaller generator applied to interconnect prior to the next tariff becoming effective, which would be unlikely, the system contribution requirement could be waived in accordance with the 2007 *Transmission Regulation*. In the case of both subsection 29(4) and section 30, the AESO acknowledged that the 2007 *Transmission Regulation* would prevail over the terms of the tariff, if a conflict were to arise prior to updating the tariff.<sup>9</sup>

The Board agrees with the AESO that in the event of a conflict between the provisions of the 2007 *Transmission Regulation* and the AESO tariff, the provisions in the regulation would prevail. However, subsection 29(4) states that the AESO tariff *must* include terms and conditions that reflect subsection 29(4). Given this, it is not sufficient to rely on the prevalence of the regulation if the tariff does not fully comply with the regulation. The Board finds the language of subsection 29(4) clearly requires the tariff to reflect that provision. As section 30 is an exception to subsection 29(4), the Board considers that these provisions must be reflected in the tariff. To that end, the Board directs the AESO propose revisions to reflect subsection 29(4) and section 30 of the 2007 *Transmission Regulation* in the refiling application resulting from this Decision.

A further issue that arose was the proposal by ADC in its evidence that any transmission system costs classified as energy-related be recovered from generators through Rate STS, rather than Rate DTS, since these costs were related to optimizing the transmission system to reduce losses (which are the responsibility of generators). ADC reiterated this in its reply argument. It

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<sup>8</sup> AESO Argument, pp. 7-8

<sup>9</sup> AESO Argument, pp. 7-8

considered that since the AESO claimed these wires costs to be energy related and caused solely for the sake of reducing line losses, recovering these costs from generators would not violate the *Transmission Regulation*.

In response to the ADC's proposal, the AESO argued that although generators can be allocated some wires costs, for example interconnection costs, those interconnection wires costs were explicitly provided for in the regulation. On the other hand, the regulation did not explicitly require the wires costs that were loss-related to be allocated to generators. Since no clear direction existed to recover a portion of wires costs from generators, the AESO argued that the ADC's proposal should be rejected. Powerex supported the AESO's position, as did TransAlta Corporation (TAU), which argued that the ADC's proposal contravened the *Transmission Regulation*.<sup>10</sup>

ADC had advocated that energy related charges linked to line loss reduction be recovered from generators in the last AESO proceeding. The Board ruled in Decision 2005-096 that these costs were not to be recovered from generators:

In its intervener evidence, ADC suggested that wires costs incurred to reduce line losses should be allocated to generators. ADC reiterated this in its reply. TransAlta Utilities (TAU) took issue with ADC's proposal, suggesting that Section 30 of the *Transmission Regulation* was clear that all wires costs were to be paid by load and only losses by generation customers. The Board agrees with TransAlta's interpretation and has been guided by this in the rate design sections that follow.<sup>11</sup>

The regulatory changes resulting in the 2007 *Transmission Regulation* occurred after the release of Decision 2005-096. The Board has reviewed the provisions of both the 2004 *Transmission Regulation*, and the 2007 *Transmission Regulation* and finds that nothing material has changed in the wording or intent in the 2007 *Transmission Regulation* which would indicate that energy related charges linked to line loss reduction should be recovered from generators. The Board finds that its ruling in Decision 2005-096 continues to apply and agrees with the AESO's interpretation of the 2007 *Transmission Regulation*. The Board therefore rejects the ADC proposal.

In a number of instances, the AESO argued<sup>12</sup> that it would consider it inappropriate to permit variations in rates based on operational considerations such as voltage level because operational considerations may, to an extent, reflect the location of the customer. As a result, such variations may violate subsection 30(3) of the *Electric Utilities Act* (EUA). Subsection 30(3) of the EUA provides:

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

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<sup>10</sup> AESO Argument, p.7, TAU Argument, p. 1

<sup>11</sup> Decision 2005-096, p. 14

<sup>12</sup> AESO Argument, p. 27

In its reply argument, the ADC submitted that the AESO's interpretation of subsection 30(3) of the EUA was too broad. The ADC submitted that this provision does not prohibit recognition in the AESO's tariff of engineering or physical differences that may cause increased costs but which are not specifically tied to location.<sup>13</sup> The Board agrees with the interpretation presented by the ADC.

In the Board's view, recognizing different operational circumstances and their cost implications does not, in itself, contravene subsection 30(3) of the EUA. That section requires only that the rates not vary as a result of the location of their systems on the transmission system (i.e. the geographic location of the POD within the province). This is consistent with the Board's finding in Decision 2001-6.<sup>14</sup> The Board is in no way commenting on whether the AESO may have justifiable reasons, separate and apart from subsection 30(3), for extending system access service to all customers regardless of their actual physical system facilities. This specific legislative provision simply does not prohibit variations in rates based on operational considerations.

Subject to any statements made by the Board to the contrary in the remainder of this Decision, the Board considers the AESO has appropriately addressed the requirements of the relevant legislation.

### **3 PHASE 1 MATTERS**

#### **3.1 Revenue Requirement Forecasts and Deferral Accounts**

The AESO outlined the processes which had occurred leading up to the Application to the Board. This included establishing a budget review committee (BRC) in May, 2005 to provide a first level of prudence review and input, resulting in a recommendation from the AESO executive to the AESO board for approval. The AESO stated that it endeavoured to further develop the consultation, review and AESO board decision process for the 2007-2008 budget, in part to ensure the process sufficiently involved stakeholders. The process included a review of not only the AESO own costs forecast, but also forecast costs for ancillary services and transmission line losses. Transparency and inclusiveness were two of the primary principles behind the redesigned process, referred to as the AESO budget review process (AESO BRP). The process and underlying terms of reference were established and agreed upon with interested stakeholders prior to entering into the budget review. Comments were provided in writing by all parties, and shared by way of distribution to the participants and posting to the AESO's website. No stakeholders were precluded from participating in the process at any point in time.<sup>15</sup>

Following a meeting with stakeholders on May 30, 2006, at which feedback was sought on a process straw model and a terms of reference document, on June 20 the AESO posted, among other things, a final detailed AESO BRP, a terms of reference document and a schedule. These documents were included as Appendix A to the Application. The process at a high level involved notice to stakeholders, development by the AESO of priorities and a strategic plan, and also of the forecasts of its own costs, ancillary services and line losses. Following this, technical

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<sup>13</sup> ADC Reply, pp. 2-3

<sup>14</sup> Decision 2001-6, ESBI Alberta Ltd. 2001 General Rate Application, Part D: Customer Contribution Policy, page 55

<sup>15</sup> Ex. 003, Application, Section 2, p. 1

meetings were held to review the AESO's forecasts & prior year actual costs. This was followed by the decision of the AESO board, and submission of the Application to the Board.

The AESO indicated that all written material for this process was posted to the AESO's website and communicated to stakeholders in a newsletter. Part of the plan is also that the process will be re-evaluated with stakeholders at the end of each budget cycle and refinements made if necessary.

The AESO indicated that as a result of the AESO BRP, on October 5, 2006, it distributed an AESO board decision document, requesting AESO board approval of the AESO's 2007/2008 strategic initiatives, general and administrative costs, general capital, losses costs, ancillary service costs, and other industry costs. The document was recommended by AESO management, based on the AESO BRP. The AESO stated that these strategic initiatives and costs were fully discussed in the Application, along with the supporting rationale, and an overview of the process undertaken by AESO management to arrive at the recommendation. The AESO stated that several stakeholder groups met with the AESO board to discuss their written comments. These materials were then discussed at the October 19, 2006 AESO board meeting, at which the AESO board approved the AESO's 2007 business plan and budget, particulars of which were set forth in section 2 of the Application. These included, among other things, the following:

1. AESO general & administrative costs of \$51.5 million for 2007
  - o Transmission costs recovery of \$35.7 million
  - o Energy market recovery of \$11.9 million
  - o Load settlement recovery of \$3.7 million
2. Interest costs of \$1.9 million for 2007
  - o Transmission costs recovery of \$1.2 million
  - o Energy market recovery of \$0.5 million
  - o Load settlement recovery of \$0.2 million
3. Amortization and depreciation of \$10.0 million for 2007
  - o Transmission costs recovery of \$4.4 million
  - o Energy market recovery of \$3.3 million
  - o Load settlement recovery of \$2.3 million
4. AESO capital costs of \$5.4 million for 2007
5. AESO other industry costs of \$5.5 million for 2007
6. AESO line loss costs of \$196.0 million for 2007
7. AESO ancillary service costs of \$184.5 million for 2007<sup>16</sup>

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<sup>16</sup> Ex. 003, Application, Section 2, p 1-3. An excerpt from the AESO Board resolution approving these amounts was included in Ex. 003, Section 2.9 of the Application.

In addition, the AESO added its forecast of the wires costs (\$445.2M) associated with the current Board approved tariffs of the Transmission Facility Owners (TFOs), to arrive at its 2007 revenue requirement forecast of \$872.5M.<sup>17</sup>

The Board is encouraged by the considerable amount of effort by the AESO and stakeholders in arriving at the 2007 revenue requirement forecast contained in the Application.

The Board is cognizant of the 2007 *Transmission Regulation*, which requires the AESO to consult with those market participants that it considers are likely to be directly affected by an approval by the AESO board of its “own administrative costs”, costs for provision of ancillary services or the costs of transmission line losses.<sup>18</sup> The AESO’s “own administrative costs” are defined as:

- (i) the transmission-related costs and expenses of the ISO respecting the administration, operation and management of the ISO,
- (ii) the transmission-related costs and expenses of the ISO respecting reliability standards and reliability management systems, and
- (iii) the transmission-related costs and expenses required to be paid, or otherwise appropriately paid, by the ISO, except for the following:
  - (A) costs for the provision of ancillary services;
  - (B) costs of transmission line losses;
  - (C) amounts payable under TFO transmission tariffs;

Sections 46(1) and 48 of the regulation provide that:

46(1) - The Board must consider that

- (a) the costs and expenses referred to in sections 39, 40 and 41 that are included in a TFO’s tariff or a DFO’s tariff, and
- (b) the ISO’s own administrative costs that have been approved by the ISO members are prudent unless an interested person satisfies the Board that those costs or expenses are unreasonable

48(1) A reference in the Act to “prudent” or “appropriate” in relation to the ISO’s costs for the provision of ancillary services and costs of transmission line losses means the amounts of those costs that have been approved by the ISO members.

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

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<sup>17</sup> The calculation of the \$872.5M revenue requirement does not include energy market, load settlement, or AESO capital costs, listed in items 1, 2, 3, 4 in the above list which total \$27.5M

<sup>18</sup> *Transmission Regulation* (AR 86/2007), sec 3(1)(b)

No parties expressed concern with the AESO's entire 2007 forecast revenue requirement being subject to deferral account treatment.

In the Board's review of the AESO 2007 revenue requirement forecast, it has not identified any significant concerns which would require modifications. The Board directs the AESO to continue its practice of updating its forecast of wires related costs to reflect any interim or final approvals granted to TFOs in its refiling application. Subject to this qualification and subject to the application of the appropriate tests during the deferral account process, the Board approves the AESO 2007 revenue requirement forecast as applied for.

TCE expressed concern in argument about the length of time being taken by the AESO to dispense with its deferral accounts, and requested that the AESO be directed to expedite its deferral account applications:

While the AESO may not have large amounts in aggregate in their deferral account balances due to the corrections involving Rider C adjustments, individual customers could be owed substantial funds and other customers could owe substantial amounts. The longer these payments are delayed, the greater likelihood that various customers could be required to make payments or receive credits materially disconnected from the period in which the liabilities or credits were incurred.<sup>19</sup>

In response to TCE's concern, the AESO submitted that no specific direction was required from the Board, given that it is taking some action regarding deferral account filings:

As discussed during the hearing (3T: 0753, line 12 to 0754, line 16), the AESO is currently finalizing a deferral account reconciliation application for the years 2004 and 2005, which will also include a second reconciliation for the year 2003.

During the process of developing the 2004-2005 deferral account reconciliation application, the AESO has developed an automated deferral account reconciliation tool. The AESO expects that this tool will allow earlier filing of deferral account reconciliation applications in the future.<sup>20</sup>

The AESO indicated that it is currently finalizing a deferral account reconciliation application for the years 2004 and 2005, which will also include a second reconciliation for the year 2003. The Board further notes the AESO statement that it has developed an automated deferral account reconciliation tool which it expects will allow earlier filing of deferral account reconciliation applications in the future.

Subsequent to the close of record for this proceeding, the Board received an application from the AESO, requesting approval of:

- a first reconciliation of the deferral account for 2005,
- a first reconciliation of the deferral account for 2004,
- a second reconciliation of the deferral account for 2003, and
- reconciliations of adjustments to deferral accounts for 1999 through 2002.<sup>21</sup>

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<sup>19</sup> TCE Argument, p. 2

<sup>20</sup> AESO Reply, p. 4

<sup>21</sup> Application 1548908

The Board is encouraged that the AESO is taking action to resolve its deferral accounts and considers that no further Board directions are required at this time.

The ASBG/PGA expressed concern in argument about the AESO stakeholder review process, which did not provide for application of the Board's cost recovery process. The ASBG/PGA requested that the Board consider sanctioning future stakeholder review processes, and deferral account proceedings, so that parties would be eligible for cost recovery.<sup>22</sup>

In reply, the AESO submitted that the use of a technical meeting or information conference is already addressed in EUB Bulletin 2005-31: *Revisions to EUB Cost Policies and Prehearing Processing for Utility Matters*. The AESO submitted that Bulletin 2005-31 provides appropriate guidance for the use of workshops and similar processes, and that these processes also apply to workshops or similar processes held in connection with deferral account proceedings. It also stated that it will consider Bulletin 2005-31 when preparing future tariff applications.<sup>23</sup>

The Board agrees with the AESO that EUB Bulletin 2005-31 provides sufficient guidance for the use of workshops and similar processes. The cost recovery process is presently governed by section 55 of the Rules of Practice and is further described in Board Directive 31B and Bulletin 2005-31. Whether or not a stakeholder session or other similar process has been sanctioned by the Board does not in and of itself guarantee that any particular participant will be eligible to recover any or all of its costs. The Board observes that section 50 of the Rules of Practice allows participants to, at any time during the proceeding, make a request to the Board for an advance of funds in accordance with Directive 31B. The Board may award an advance of funds to a participant only if the participant demonstrates a need for financial assistance to address relevant issues in the proceeding. The Board considers that it is not necessary or desirable to explicitly determine in this Decision the level of Board involvement in future workshops or stakeholder sessions.

#### **4 PHASE 2 MATTERS -RATE DESIGN PRINCIPLES**

A common rate design evaluation guideline used in the past by the Board in its previous decisions is a set of principles known as Bonbright's criteria. Parties referenced many of these principles in support of their rate design proposals in this proceeding.

The AESO referenced the same Bonbright principles that it put forth in its 2006 application, and referred to the Board's previous discussion of these principles:

In its 2006 tariff application, the AESO identified five rate design principles applicable to a utility (adapted from *Principles of Public Utility Rates* by Bonbright, Danielsen, and Kamerschen, 2nd ed., 1988, pp. 385-389):

- (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;

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<sup>22</sup> ASBG/PGA Argument, p. 1

<sup>23</sup> AESO Reply, p. 1 and p. 4

- (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.

The first principle would be satisfied by any rate design that, on a forecast basis, recovered the applied-for revenue requirement.

In Decision 2005-096, the EUB considered that the second and third principles would 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 becomes the primary consideration when evaluating a rate design proposal.

Also in Decision 2005-096, the EUB found that the remaining two principles should be given secondary consideration. That is, considerations of stability and of practicality should only cause deviation from cost-based rates in respect of unusual regulatory events, dramatic changes in cost structure, or where cost causation provides limited guidance in evaluating a rate proposal.<sup>24</sup>

In argument, the AESO listed additional criteria which it considered important in evaluating the AESO's proposed rates. However, the AESO ultimately reiterated that cost causation was the most critical element in satisfying the five Bonbright principles that it endorsed.<sup>25</sup>

IPCAA agreed that it was of utmost importance that the rate design reflect an allocation of costs as accurately as possible in order to send correct price signals:

Standard practice in cost studies is to allocate costs to customer classes after functionalizing and classifying those costs. As the AESO maintains a single DTS tariff, there is no explicit step to classify costs. Effectively, the rate design allocates costs among users with differing usage characteristics. For this reason, it is important that the rate design reflect the nature of the transmission costs to the greatest degree possible. The Board provided direction in this regard in the last decision:

The Board considers that appropriate price signals typically will be sent when costs are being recovered in the manner in which they are caused, that is, demand related costs are recovered through a demand charge, energy related costs are recovered through an energy charge, and fixed costs are recovered through a fixed charge.<sup>26</sup>

TCE developed its own list of criteria,<sup>27</sup> which included considerations such as efficiency (prices should be designed to promote efficient use of the transmission system), value of service (some prices should be discounted to reflect lower value of service), and comparability (prices should be designed to reflect a consideration of comparable services offered in other jurisdictions).<sup>28</sup> TCE argued that

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<sup>24</sup> Ex. 005, AESO Application, Rate Design section, pp. 4-5

<sup>25</sup> AESO Argument, pp. 9-13, p. 17

<sup>26</sup> Ex. 237, IPCAA Evidence, p. 6

<sup>27</sup> TCE indicated that it had derived these criteria based on Board Decision 2000-1, p. 73

<sup>28</sup> TCE Evidence, p. 6

efficiency, value of service, and comparability merited separate identification as rate design principles.<sup>29</sup>

The ADC submitted in argument that the Board should embrace certain rate design considerations, including upholding prior Board decisions (absent compelling evidence for not doing so), and considering cost consideration to be the primary factor in rate design.<sup>30</sup>

Parties made extensive submissions on rate design principles in their evidence, argument, and reply argument. Despite this comprehensive volume of information, the Board has not been persuaded that the criteria used to evaluate the AESO's proposed rate design should vary from that used in Decision 2005-096.

The Board continues to believe that the following three primary Bonbright principles, as cited in Decision 2005-096, should be given the most weight in evaluating a rate design:

1. Recovery of revenue requirement,
2. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service, and
3. Fairness, objectivity, and equity that avoids undue discrimination and minimizes intercustomer subsidies.

The Board considers any rate design that, on a forecast basis, recovers the applied-for revenue requirement will satisfy the first principle.

The second and third principles will 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.

The Board maintains that cost causation therefore remains the primary consideration when evaluating a rate design proposal. This finding is in alignment with Bonbright and also with the majority of the parties in this proceeding. The Board agrees with IPCAA's statement that the main issue in this proceeding is the definition of transmission cost causation.<sup>31</sup>

What is abundantly clear, though, is that parties disagree on the method used to determine cost causation, and are using either certain of Bonbright's criteria or principles developed on their own in support of their proposed cost allocation methods. Typically, the cost allocation methodology endorsed by a given party will result in fewer costs being allocated to that party.

The Board has found that the remaining two principles identified by the AESO should be given secondary consideration. That is, on balance, if rates reflect causation, barring unusual regulatory

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<sup>29</sup> TCE Argument, pp. 6-7

<sup>30</sup> ADC Argument pp. 2-5

<sup>31</sup> IPCAA Reply, p. 2

events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism.

The Board has previously ruled in Decision 2005-096 (and again in this Decision) that the first three primary Bonbright principles stated above are to be given the most weight, and that the remaining two Bonbright principles merit secondary consideration.

The Board has found that the three additional criteria proposed by the TCE would merit less consideration in evaluating a rate design. In general, value of service and efficiency will be achieved by a proper cost allocation and rate design.

If the cost causation principle is satisfied by a rate design, then proper price signals will be sent to customers, and these price signals will act as an incentive for customers to use the system efficiently. As such, the Board does not agree with TCE that it must explicitly recognize efficiency. Rather, efficient system use is a by-product of a rate design based on a proper cost allocation.

The value of service criterion will also be satisfied by a proper cost allocation and rate design. For example, the AESO's proposed DOS rate is assigned a portion of costs which are in alignment with the reduced value of interruptible service rather than firm service. The cost assignment is also tempered in recognition that opportunity service does not cause system costs, but rather provides additional revenue in exchange for the use of spare capacity on the system. Opportunity service will therefore be allocated less cost than base rates, but the allocated costs will be in alignment with the value of the service. As such, the Board does not agree with TCE that the value of service criterion need be separately identified.

Regarding the comparability criteria, the Board does not consider prices for services offered in other jurisdictions to be determinative, and does not consider that such a consideration would outweigh the principle of cost causation. The Board considers the comparability criteria to be difficult to use, in that the AESO does not have any peer transmission administrators in the province to compare its tariff against. While the Board is mindful that transmission administrators exist in other jurisdictions outside of Alberta, comparing the rates approved in this Decision to those of other jurisdictions does not merit the same weight as the three primary Bonbright criteria.

A number of parties, most notably the AESO, Pipeline Power Group and Associates (PPGA), and DUC made comments about the application of rate design principles to the design of the POD charge component of Rate DTS. Each of these parties appeared to agree that, as with the other components of the AESO's DTS rate, cost causation should receive a significant weighting in the design of the DTS POD charge. However, while PPGA appeared to support the importance of basing rates on cost causation, it also suggested that the data and analysis supporting a rate change must be free from uncertainty before a change in rate design is supportable. The Board does not share PPGA's view.

The rate design principles of cost causation and rate shock avoidance are not of equal importance. Effectively, PPGA's approach imposes a pre-condition on the use of cost causation as the pre-eminent rate design principle if a proposed rate change creates a significant change in the rates paid by specific customers. However, as articulated in Decision 2005-096, the Board reaffirms that cost causation should also receive pre-eminent consideration amongst Bonbright

principles as applied to the design of the POD charge. Thus, while rate shock remains a valid consideration in the design of any rate, including the POD charge, rate shock should be addressed as a separate stand alone issue after cost causation has been determined. The Board deals with rate shock in section 5.9 of the Decision.

## 5 PHASE 2 MATTERS - DTS RATE DESIGN

### 5.1 DTS Rate Design – Overview

In the Application<sup>32</sup> the AESO proposed significant changes to the design of the DTS rate, particularly with regard to the allocation of the bulk and local wires components of the DTS rate. The changes proposed to the DTS rate are as follows:

- The re-bundling of the bulk and local system charges into a single system charge
- The collection of the demand related portion of this charge using non-coincident peak (NCP) allocator, including a ratchet incorporating a billing capacity factor
- The collection of a significant portion of wires costs on an energy basis as determined by the use of the average and excess methodology (A&E) proposed in the Application

In support of these changes, the AESO included in the Application a 2006 Transmission Cost causation Update<sup>33</sup> (TCCU), prepared by Mr. Arnie Reimer of PS Technologies Inc., and an additional analysis of bulk system data (Appendix D).<sup>34</sup> Most of the TCCU and all of Appendix D are dedicated to verifying the hypothesis, as stated in the TCCU:<sup>35</sup>

that for Alberta as a whole, the correlation between the time of maximum stress on the bulk system and the hour of AIL peak system load is weak or non existent. For most areas of Alberta, the time of maximum stress on the Bulk system does not coincide with the time of the annual peak system load.

The above hypothesis serves as the foundation for the significant changes proposed to the collection of bulk and local wires costs (as summarized above). Contrary to the expectation expressed during the AESO's 2005-06 GTA hearing, the TCCU found that there was a very weak correlation between individual bulk line loading and total Alberta Internal Load (AIL), being the total domestic consumption of Alberta Interconnected Electric System (AIES) loads in Alberta.<sup>36</sup> As such, the AESO concluded that load in any hour reflects cost causation and ought to be the basis for formulating rates. The AESO submitted that recovering bulk system costs on a Coincident Peak (CP) basis is not justified from a cost causation perspective.

The Application did not propose to change the calculation of the ratchet contained within the DTS rate, but did propose to extend the ratchet to the bulk wires component. The ratchet in the current tariff applies to the local wires component and the POD charge component of the DTS rate. The proposal to extend the ratchet to the bulk wires component was consistent with the

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<sup>32</sup> Ex. 005, Application, Section 4

<sup>33</sup> Ex. 012, Application, Appendix C (TCCU)

<sup>34</sup> Ex. 013, Application, Appendix D

<sup>35</sup> Ex. 012, TCCU, p. 4

<sup>36</sup> Ex. 005, Application, Section 4, p. 8

proposal to “rebundle” the bulk and local wires components into a new “system charge” that would bill for both bulk and local wires on the same basis. It is this extension of the ratchet to the bulk wires cost portion of the DTS rate that was contentious. The Board deals with the applicability of the ratchet to bulk wires costs in section 5.5.1 and section 5.8 of this Decision.

The AESO has also proposed changes to the POD charge component of the DTS rate. In particular the AESO has proposed the collection of a significant portion of the POD component of the DTS rate through demand charges, using a ratcheted NCP approach, in contrast to the significant customer related charge in the current tariff. As stated by the AESO in section 4 of the Application:

As noted in section 4.2 of this Application, the EUB considered that rates should recover costs in the manner in which they are caused. The recommended cost function provided in equation 1 is reflective of the costs caused by a customer interconnection at a POD. The AESO therefore proposes to classify POD costs based on the cost function provided in equation 1, as detailed in Table 4.3.6.

The AESO therefore proposes to classify point of delivery costs 12.3% as customer-related and  $53.9\% + 33.8\% = 87.7\%$  as demand-related, compared to the 56.2% customer-related, 43.1% demand-related, and 0.7% usage-related in the original *Transmission Cost Causation Study*. (The AESO notes that the 0.7% usage-related component was re-classified as customer-related in response to Direction 6 in the AESO’s 2005-2006 GTA Refiling dated September 27, 2005.)

The AESO recognizes that the classification based on the detailed examination completed to in the *Contribution Policy Study* differs significantly from that based on the zero-intercept analysis presented in the original *Transmission Cost Causation Study*. The proposed classification is based on the more detailed examination of costs completed in the *Contribution Policy Study*. As well, the AESO considers that the proposed classification recognizes that a different cost function is appropriate for smaller interconnection projects, as discussed in more detail in section 4.5 of this Application.<sup>37</sup>

A summary of the Board’s findings regarding the DTS Rate is included in section 5.8 of this Decision. Prior to ruling on the proposed changes to the DTS rate, the Board will examine the hypothesis, referenced above, contained in the TCCU.

## 5.2 DTS Rate Design, Transmission Cost Causation Update Hypothesis, Appendix D

In the Application, the AESO stated that it sought to base its rate proposals on cost causation principles as much as possible, and that in particular, it relied on a 2006 Transmission Cost Causation Update (TCCU) (Appendix C to the Application) as the basis for functionalizing and classifying costs for the proposed rates.<sup>38</sup>

The TCCU strove to conduct a “more thorough review of all those lines comprising the bulk system,” as directed by the Board in Decision 2005-096. This included interviewing AESO system planners (regarding transmission paths, upgrades to the bulk transmission system, and causes of maximum stress on bulk transmission lines). This qualitative review was followed by a

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<sup>37</sup> Ex. 005, Application, Section 4, p. 14

<sup>38</sup> Ex. 005, Application, Section 4, p. 5

quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL).

Section 2 of the TCCU, which constituted the majority of the TCCU, studied the requirements that drove upgrades to the bulk system. As the TCCU stated:

This study consists of the following three sections:

- a) Interviews with planners to review transmission paths and the need to upgrade the system to accommodate load growth,
- b) A study of correlation between loading on Bulk System components (240 kV lines) and AIL, and
- c) A study of correlation between line loading as percent of thermal capacity and AIL.<sup>39</sup>

The TCCU summarized its qualitative review gathered through interviews with planners as follows:

This qualitative assessment shows that transmission planning is very complex and is not dominated by any one simple factor such as AIL peak load. Transmission planning is driven by a large number of independent factors such as the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta.<sup>40</sup>

A quantitative analysis was undertaken to assess the correlation between the time of maximum stress on the bulk system and the time of AIL peak load. For purposes of this study the 240 kV circuits are assumed to represent the bulk system. Meter data was obtained for each 240 kV circuit, by hour, and for all 8760 hours, in each of 2004 and 2005. The AIL load by hour was also obtained by hour over the same period. The TCCU acknowledged that since all meter data is actual data, the analysis had some shortcomings. For example, transmission planning is conducted without including opportunity sales; however actual meter data includes any opportunity sales that occurred. The meter data included actual imports and exports (opportunity sales). The AESO maintained that the total amount of exports was small in comparison to the Alberta load (1.5%) and therefore any adjustment for exports would have only a minimal impact on the circuit loading data.<sup>41</sup> Also, no provision was made for adjustments to the meter data to account for abnormal conditions, such as transmission contingencies or generator outages.

The TCCU analyzed the circuit load and AIL to determine a correlation coefficient between the two. A total of eighty 240 kV circuits were studied for line loading correlation to AIL load (representing 85% of the bulk system lines on the basis of NBV). Results were provided for 79 of the 80 circuits, representing 57 AltaLink circuits and 22 ATCO Electric circuits. No party questioned the results for the eightieth line in argument. Based on metered data for the 8,760 hours, individual bulk line loads over all 79 240 kV bulk transmission lines in Alberta (weighted by line length) in 2005 showed only an 8% correlation with AIL and in 2004 showed only a 1% correlation.<sup>42</sup>

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<sup>39</sup> Ex. 012, TCCU, p. 8

<sup>40</sup> Ex. 012, TCCU, p. 13

<sup>41</sup> Ex. 012, TCCU, p. 14

<sup>42</sup> Ex. 005, Application, Section 4.3.2, p. 8

The TCCU concluded, based on its analysis, that the relationship between AIL peak load and circuit load (weighted by a number of factors) was weak or non-existent.<sup>43</sup>

To confirm the results of the TCCU, the AESO provided further analysis in Appendix D to the Application. Appendix D provided a variety of graphs that illustrated the lack of coincidence between loads on individual bulk transmission system lines and system load in aggregate. The graphs rely on hourly metered data examined for the TCCU provided, namely, 8,760 hours of data for each of seventy-nine 240 kV 15 lines for 2005, and 8,784 hours of similar data for 2004 (since 2004 was a leap year). The AESO stated the observations in Appendix D<sup>44</sup> further supported the conclusion that system peak is not reflective of loading on individual bulk system transmission lines, and is therefore inappropriate as a basis for recovering the cost of those lines.

The AESO summarized its research and conclusions with respect to classification of bulk wires costs at subsection 4.3.2 of the Application. The AESO stated:

As discussed above, the bulk transmission system, on average, exhibits no distinct hourly or monthly usage patterns. Loading on the bulk transmission system varies from 97% to 103% of average on an hourly basis, and from 93% to 111% of average on a monthly basis. In effect, some bulk lines are heavily loaded, and some are lightly loaded, in every hour of the day and every month of the year. Load in every hour is therefore important, since in every hour some bulk lines will be heavily loaded and will need reinforcement if additional load is to be accommodated. There appears to be no basis to support cost recovery based on loading at different times of day and different months of the year.<sup>45</sup>

TCE, ADC, IPCAA, Powerex and EnCana discounted the usefulness of the TCCU, stating there were serious flaws in the analysis. TCE supplied a significant amount of evidence regarding the allocation of bulk transmission wires costs. In particular TCE supplied as Appendix A its own Analysis of Transmission Usage on Bulk Transmission System, Appendix D – limitations of using transmission usage data rather than transmission planning studies, Appendix F on the limitations on the accuracy of the AESO's Cost of Service Study and Appendix G on historical drivers of bulk transmission costs.

In Appendix A to its evidence, TCE identified a number of deficiencies in the TCCU. TCE noted that the AESO had studied all 8,760 hours in the years in question. TCE submitted all 8,760 hours during a year are largely irrelevant to transmission planners and results in the loss of important correlations between system peaks on lines and AIES peaks.<sup>46</sup> It submitted that when transmission planners identify that there is adequate transmission line capacity (after contingencies) to meet the peak flow conditions, those facilities will also normally be adequate to handle flows that are considerably less than the peak flows. TCE submitted that transmission planners are interested in the peak load in the hour when a transmission line peaks. It considered that transmission planners may also be interested to a lesser extent in load peaks that are close to the annual peak as the circumstances governing the near peaks could become dominant for future

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<sup>43</sup> Ex. 012, TCCU, p. 28

<sup>44</sup> Ex. 013, Application, Appendix D, pp. 1-2

<sup>45</sup> Ex. 005, Application, Section 4, pp. 11-12 (emphasis in original)

<sup>46</sup> Ex. 242, TCE Evidence, Appendix A, p. 1

peaks. For this reason, TCE examined when the top ten transmission line peak flows occurred on the transmission lines examined in the TCCU.

With respect to line loadings, in its evidence, TCE analyzed the 240 KV transmission lines that were examined in the TCCU in the north-south system. It then analyzed the remaining transmission lines. It found a number of peaks occurred in off-peak hours in the Calgary area. TCE then analyzed the data to determine the causes for peaking of these transmission lines in off-peak hours, and found that those peaks coincided with substantial exports.<sup>47</sup> TCE noted the constraints on the north-south system are determined by power flows on the 6 – 240kV lines that run between the Edmonton area and Calgary combined with power flows from a 240 kV line (912L) from Red Deer east towards Battle River and offset by power flows from the Brazeau hydro plant on a 240 kV line (995L). TCE provided details of its analysis of the three areas at pages 2-10 of Appendix A to its evidence.

TCE amalgamated the results for the three separate areas and the results were shown in Figure A9. TCE stated it could be seen from Figure A9 that there are two strong peaks, one in the early afternoon and one at the hour ending 6 PM. This is the typical time when the AIL peaks in summer and winter, respectively. TCE maintained while there may not be a one-to-one correlation between any individual transmission line and AIL peaks, it is clear that in aggregate, there is a reasonable propensity for the transmission lines to peak when the AIL peaks. This is a logical conclusion in that periods when the load across the province is peaking is when the most generation is on-line and the most energy needs to be transferred. In conclusion TCE stated while the transmission system is complex and clearly impacted by export behaviour in night time hours, removal of those effects confirms the likelihood that AIL peaks are reasonably well linked with transmission line peaks and are therefore a reasonable proxy to transmission line cost causation.

In Appendix D to its evidence, TCE outlined the limitations of using unadjusted transmission usage data in a cost of service study.<sup>48</sup> TCE noted the AESO had used actual power flow data when attempting to determine when the bulk transmission system was stressed.

In argument TCE continued to be critical of the TCCU. In particular TCE claimed that peak load mattered, not the load flows for all 8760 hours. TCE referred to the following passage from the transcript of the oral hearing, in which its witness Mr. Levson references the AESO's planning criteria:

I'm quoting from the AESO's transmission reliability criteria. And on page 20, this is dated March 11th, 2005, they state (quoted as read):

"The ATS will be designed to supply forecast peak load and peak flows based on a forecast of megawatt hours per hour in a normal weather year."

Then they read -- then they say (quoted as read):

"There are elements or paths of the system that may need to be designed to accommodate peak loads that are substantially higher when measured over shorter durations."

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<sup>47</sup> Ex. 242, TCE Evidence, Appendix A, p. 8

<sup>48</sup> Ex. 242, TCE Evidence, Appendix D, p. 1

So I believe that would be less than an hour. They have to manage peaks -- very short peaks that may occur. And then they say (quoted as read):

"The loads to be used for specific geographic areas are the expected forecast coincident peak loads for load areas."

To me, that's very clear how the planners plan the system. I've sat in sessions with them where they have explored -- or shown us how they actually do this. And they basically increment the load up in an area year by year until the criteria starts to fail. They don't look at other loads except in exceptional situations.<sup>49</sup>

TCE stated that the AESO generally agreed that a "contingency that occurs when a transmission line is peaking is more likely to stress the system than a contingency that occurs when the transmission line flows are much less than the peak."<sup>50</sup>

ADC also supplied evidence in this matter, noting that the TCCU had not taken into account export loads and had not taken account of contingency planning.<sup>51</sup> ADC continued to be critical of the TCCU in argument, noting many of the same flaws identified by TCE.<sup>52</sup> ADC also noted that the AESO appeared to agree that the bulk system should be viewed as a whole.<sup>53</sup>

ADC supplied examples, Schedules 7 and 8, to illustrate the effect of increasing load and planning for contingencies. In Schedule 8 the total load on the system increased by 300MW while the loading on one of the lines actually decreased. Dr. Rosenberg was therefore not surprised that Mr. Reimer's analysis showed some individual lines were not correlated with system peak. Dr. Rosenberg explained in his analysis that the TCCU analysis was weak because it did not take into account contingency planning. Dr. Rosenberg also stated in his analysis that it was the aggregate load at node C (the coincident load when all the node C customers are peaking) that was the primary consideration, not the sum of the individual contract or individual non-coincident loads of the customers.<sup>54</sup>

EnCana, Powerex, ASBG/PGA and IPCAA were also critical of the TCCU. EnCana argued that the TCCU's quantitative analysis was overly simplified and that it did not fully reflect how the system is planned.<sup>55</sup> EnCana maintained Appendix D was equally incompatible with traditional system planning.<sup>56</sup> It also noted that Mr. Martin had acknowledged that it is a method that had never been used in the preparation of any planning studies, the AESO's 10-year plan, or a need application.<sup>57</sup>

EnCana submitted that the lack of a demonstrable consistency between the TCCU/Appendix D on one hand and traditional planning on the other meant that the TCCU/Appendix D studies are

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<sup>49</sup> Tr. Vol. 6, p. 1110

<sup>50</sup> Tr. Vol. 2, p. 472, lines 7 to 13

<sup>51</sup> Ex. 221, ADC Evidence, pp. 40-41

<sup>52</sup> ADC Argument, pp. 16-20

<sup>53</sup> ADC-AESO-5c

<sup>54</sup> Ex. 221, ADC Evidence, pp. 41-42

<sup>55</sup> EnCana Argument p. 9, refers to TCCU, p. 13

<sup>56</sup> EnCana Argument p. 10, refers to ADC Evidence (Ex. 221) p. 33

<sup>57</sup> EnCana Argument p. 10, refers to Encana-AESO-6, and Tr. Vol. 2 pp. 490-491

not reliable sources for the Board to draw any inferences as to who causes costs. It further submitted that the Board should therefore reject these studies and their conclusions.

Powerex submitted that the interviews conducted with transmission planners which were used in the TCCU, were not focused on the demand factors that lead to a need to expand the transmission system, but rather appear to have focused on identifying all factors that contribute to system stress.<sup>58</sup> Powerex submitted that while system stress might indicate that an expansion is required, it might also indicate that the AESO simply needs to take other action (other than system expansion) to relieve that stress. This might include for example restricting opportunity service load flows to mitigate stress. Powerex submitted that the TCCU shows that high export loads appear to contribute to system stress on both Southern Alberta and Central Alberta facilities.<sup>59</sup> It considered, however, that the AESO should not expand the transmission grid to meet the requirements of opportunity service exports. In addition, Powerex also submitted that the TCCU indicates that Southern Alberta stress is caused by wind generation, which does not provide any useful information for classifying costs, given the legislative constraints under which the AESO must design rates.

Therefore, Powerex maintained that the TCCU's focus on system stress does not provide particularly useful information from system planners regarding the types of *demands* that will cause expansion of the transmission system. It also pointed out that the AESO did not place a transmission planning expert on its witness panel to assist the Board and interveners in evaluating this issue.

ASBG/PGA submitted that the last graph in Appendix D to the Application, on page 17 of 17, shows the importance of the peak hour and peak hours to transmission planning and therefore cost causation on the transmission system.

Extensive evidence was filed with respect to the analysis contained in the TCCU and Appendix D of the Application. This is understandable as the TCCU forms the underpinning of the major changes to the structure of the DTS rate.

The Board concludes that it cannot accept the hypothesis as posited in the TCCU, and as supported in Appendix D. The Board does not accept that for Alberta as a whole, the correlation between the time of maximum stress on the bulk system and the hour of AIL peak system load is weak or non-existent. The Board also does not accept that for most areas of Alberta, the time of maximum stress on the bulk system does not coincide with the time of the annual peak system load.

In particular, Appendix A to the evidence of TCE demonstrates that there is indeed a reasonable degree of correlation between line loading and system peak. In Appendix D to its evidence, TCE has noted other flaws with the TCCU. The Board also notes the evidence of Dr. Rosenberg with respect to contingency planning. The Board finds that the AESO has not effectively refuted the evidence and arguments of the interveners.

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<sup>58</sup> Powerex Argument, p. 20

<sup>59</sup> Ex. 012, TCCU, Table 1

The Board considers that the bulk system must be viewed as a whole. It must be planned to accommodate peak load and account for contingencies and changes in load flows. The Board notes that it need look no further than the testimony of the AESO's witnesses Mr. Reimer and Mr. Martin for confirmation of this. Under cross examination by counsel for the ADC, Mr. Secord, Mr. Reimer and Mr. Martin stated the following:

Q Would you agree that the transmission system is generally planned and operated to meet peak demand conditions?

A MR. REIMER: Yes, the transmission system is planned to meet peak demand, and it is also planned to optimize the total cost of the transmission system, which is a total cost of capital costs plus losses.<sup>60</sup>

...

Q In Information Request ADC.AESO-005(a), which is Exhibit 094, the ADC posed the following question to the AESO....:

"Does the AESO agree that peak demands of large groups of customers are a cost driver of the bulk...system in Alberta?"

The AESO answered as follows....:

"The AESO considers that peak demands of all customers are a cost driver of the bulk transmission system. The costs of the transmission system are primarily demand-related, as detailed in the original Transmission Cost Causation Study and in the 2006 Transmission Cost Causation Update, and customer demand would therefore be a cost driver."

Did I read that correctly?

A MR. REIMER: Yes, I think so.

Q And has the AESO changed its mind on that response?

A MR. MARTIN: No.<sup>61</sup>

...

Q Does the AESO agree with the following statement....:

"Peak load is a primary cause of maximum stress on transmission lines"?

A MR. MARTIN: Yes.<sup>62</sup>

The meter data used in the TCCU included actual opportunity sales that had occurred. The AESO maintained that the total amount of exports was small in comparison to the Alberta load (1.5%) and therefore any adjustment for exports would have only a minimal impact on the circuit loading data.<sup>63</sup> TCE, in its evidence, adjusted the data to largely remove the export component of opportunity sales.<sup>64</sup> The Board considers TCE's evidence to be based on a thorough analysis and

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<sup>60</sup> Tr. Vol. 2, p. 289

<sup>61</sup> Tr. Vol. 2, pp. 307-308

<sup>62</sup> Tr. Vol. 2, p. 324

<sup>63</sup> Ex. 012, TCCU, p. 14

<sup>64</sup> Ex 242, TCE Evidence, p. 12 and Appendix A

considers the adjustments made by TCE to be an improvement in the data. The Board considers that the inclusion of opportunity export sales in the data used in the TCCU has obscured the correlation that can otherwise be seen. The Board observes that the impact of removing export sales was larger than the 'minimal impact' anticipated by the TCCU. The Board also observes that both export opportunity sales and domestic opportunity loads can be interrupted. While the AESO may be correct, and load in every hour is important; in the Board's view, system peaks influence the planning of the transmission system, and are more important than load in every hour.

For these reasons, the Board rejects the hypothesis that there is a weak correlation between circuit load and the system peak. The Board considers that system peaks are more important than load in every hour. The transmission system is planned for peak load. As acknowledged by the AESO under cross examination by Mr. Secord, peak load is the primary cause of maximum stress. The transmission system must be planned and built to withstand this stress. It follows that peak load is the cause and primary driver for bulk system costs. Given that peak load is the primary driver for bulk system costs, the Board finds that it is the primary basis on which costs are to be allocated.

### **5.3 Functionalization**

#### **5.3.1 Functionalization - General**

The Board will now review the functionalization (identification of transmission assets as bulk system, local system, or POD related) and classification (cost causation due to demand, usage, or customer existing) of wires costs.

In Decision 2005-096, the Board found the AESO's Transmission Cost Causation Study (TCCS) to be "an excellent first step" with respect to functionalizing, classifying, and allocating the bulk, local wires, and POD costs, and relied upon the TCCS in the development of its approved rate design.<sup>65</sup>

The Board also indicated in Decision 2005-096 that certain pieces of the TCCS should be examined further in future applications.<sup>66</sup>

The AESO noted that in response to Decision 2005-096, it had agreed with its stakeholders on certain items which required further study, and indicated that the TCCU addressed several of these items.<sup>67</sup> As a result of the additional work performed by PS Technologies in the TCCU, some changes were made since Decision 2005-096,<sup>68</sup> resulting in the following proposed functionalization and classification of wires costs:

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<sup>65</sup> Decision 2005-096, p. 18.

<sup>66</sup> Decision 2005-096, p. 23 "The Board expects that, in future studies, the AESO will conduct a more thorough review of all those lines comprising the bulk system. This should give a more accurate indication as to the exact portion of costs that are energy related."...."Nonetheless, based upon the percentage that O&M expenses comprise of a TFO's revenue requirement,<sup>66</sup> the Board considers that such an analysis would support a reasonable classification of costs as energy related. The Board expects the AESO to address these issues in future cost of service studies."

<sup>67</sup> Ex. 012, Application, Appendix C, TCCU, p. 2.

<sup>68</sup> Decision 2005-096, p. 18.

**Table 1. 2006 Functionalized and Classified Wires Costs (“Updated” % of Total)**

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	41.7%	34.0%	7.7%	-
Local System	17.4%	14.3%	3.0%	-
POD	40.9%	17.6%	0.3%	23.0%
<b>Total</b>	<b>100.0%</b>	<b>66.0%</b>	<b>11.0%</b>	<b>23.0%</b>

Source: Application Table 4.3.4 (Application Section 4.3.1, p. 8) – totals may not add due to rounding.

The smallest change was a reduction in bulk wires costs classified as usage related, while the largest change was an increase in total POD costs by 1%.

The TCCU also suggested potential future functionalization refinements for future cost causation updates, particularly regarding the distinction between local system and POD as well as the relationship of OM&A to age and equipment type. In the case of the OM&A study, PS Technologies suggested that due to the small proportion of total TFO revenue requirement that is comprised of OM&A costs, modifying the functionalization of these costs may not have much impact on the TCCU results.

The Board considers that the TCCU represents the appropriate cost of service starting point. The AESO, working in conjunction with its stakeholders, has performed additional studies and implemented the results of these studies in improving the TCCS approved for use by the Board in Decision 2005-096. The Board approves the functionalization percentages contained in Table 4.3.4 of the Application as filed.

The Board directs the AESO to compare the value of the additional TCCU refinement recommendations proposed by PS Technologies against the cost of performing the additional research, present the results in its next GTA, and to propose at its next GTA any refinements it considers warranted.

### 5.3.2 Functionalization (Proposed Re-Bundling) of Local and Bulk Wires Costs

As discussed above, the TCCU subfunctionalized the transmission assets into bulk wires, local wires and POD assets.<sup>69</sup>

In Decision 2005-096, the Board directed the AESO to unbundle the bulk and local wires costs for purposes of DTS rate design. At that time the Board considered that an unbundled rate design would allow for a rate more reflective of cost causation and send more appropriate price signals to customers.<sup>70</sup>

As a result of the analysis conducted in the TCCU and in Appendix D to the Application the AESO accepted the hypothesis that peak load did not correlate to maximum stress on the system and that it was load in all hours that mattered. The AESO has therefore proposed that bulk wires and local wires be classified and allocated on the same basis – that is with a demand component allocated on the basis of non-coincident peak (NCP) with a billing capacity ratchet and an energy component collected on the basis of all hours usage. In the AESO’s view, this provides a rate

<sup>69</sup> Ex. 012, TCCU, p. 52

<sup>70</sup> Decision 2005-096, p. 26

with a combined system charge that is better aligned with the AESO's contribution policy (which differentiates only between system-related and customer-related costs).

The Board has in section 5.2 above rejected the hypothesis that there is a weak correlation between circuit load and the system peak. The Board considers that system peak is more important than load in every hour. The Board continues to be of the view that unbundled costs (that is, separate rate components for bulk and local wires) will allow the flexibility to design rates more reflective of cost causation and allow for more appropriate and effective price signals to customers. The Board therefore rejects the AESO proposal to rebundle bulk and local wires costs in the DTS rate design.

#### **5.4 Classification of Bulk and Local Wires Costs**

After transmission assets are sub-functionalized into bulk wires, local wires and POD assets, and the causes of costs are assessed for each, wires costs are then classified depending on whether the cost is incurred to meet demand or varies with energy. POD costs are then assessed to be either demand or customer related. In the Application, the AESO proposed to use its proposed A&E methodology to classify wires costs.

##### **5.4.1 Proposed Average & Excess Method**

As noted above, the AESO has submitted that it is load in all hours that matters for purposes of cost allocation. This acceptance has also allowed the AESO to conclude that collecting costs on an energy basis is appropriate and therefore to classify a significant (48.5%) portion of bulk and local wires costs as energy related, using its proposed A&E methodology. The AESO explained its proposed A&E method in subsection 4.5.1 of the Application as follows:

In the average and excess method, the average component is determined by the average system load factor. The AESO considers the appropriate system load factor to use is that of the bulk transmission system lines which were examined as part of the *2006 Transmission Cost Causation Update*. The length-weighted average 240 kV line load factor was 50.0% in 2005 and 47.3% in 2004. The AESO recommends using the average of these two load factors, namely 48.6%, to determine the energy-related classification of transmission system costs.

Although the 240 kV lines were primarily functionalized as bulk system in the *Transmission Cost Causation Study*, the average line load factor is likely representative of both bulk and local systems due to the similarity of the systems as discussed above. The AESO therefore recommends the 48.6% energy-related classification of both bulk system and local system costs.

The excess component represents the amount of system load above the average, and is simply the balance of costs which is recovered on a non-coincident peak basis. From the length-weighted average 240 kV line load factor discussed above, 51.4% of transmission system costs would be classified as demand-related and recovered through demand charges.

The AESO recommends the 48.6% energy-related and 51.4% demand-related classification for recovery of the entirety of transmission system costs. The average and excess method is generally an alternative to the minimum system approach which was

utilized in the original *Transmission Cost Causation Study*, and the two approaches should not be applied together.<sup>71</sup>

The AESO stated that it proposed its A&E methodology primarily as a result of the qualitative and quantitative analysis of bulk system line loading. That analysis was undertaken to investigate the relationship between loading on individual bulk system transmission lines (as representative of maximum stress) and total AIL, and found that there was very weak correlation between the two. After additional analysis, the AESO concluded that recovering bulk system costs on a coincident peak basis (as in its current tariff) cannot be justified from a cost causation perspective.

In particular, the AESO suggested the lack of bulk line loading coincidence with system peak is clearly illustrated by the peak day profiles for each individual 240 kV line in each month of 2005 and 2004 provided in Appendix D to the AESO's Application.<sup>72</sup> The AESO submitted that these graphs demonstrate that the monthly hour of system peak is not reflective of maximum loading on individual bulk system transmission lines, and is therefore inappropriate as a basis for recovering the cost of those lines.

The AESO noted some parties suggested that its proposed A&E methodology is non-standard, and stated that it understands that there is no generally-accepted standard A&E methodology. It quoted from *Principles of Public Utility Rates*,<sup>73</sup> that "There have been several variants of the A&E method used in various jurisdictions including assigning the average demand portion by both load and diversity factors; employing peak and base methods; and using noncoincident demands." It also acknowledged that the A&E methodology has not generally been applied to transmission systems except when generation costs are allocated on the same basis.<sup>74</sup> The AESO submitted that its proposed A&E methodology should be evaluated on its own merits, rather than discarded because it does not align with a non-existent "standard" approach.

The AESO submitted that generally, the classification methodology adopted for rate design will have minimal impact on the allocation of costs among high load factor customers (although it acknowledged that it may affect the amount of costs allocated to high load factors customers compared to, for example, low load factor customers). The AESO explained that there is generally little opportunity for high load factor customers to reduce charges under any methodology, since approximately the same load would be using the system all the time.<sup>75</sup>

The AESO stated the classification methodology will have greater impact on the allocation of costs among the AESO's 138 PODs that have moderate load factors (between 40% and 60%) and among the 117 PODs that have low load factors (below 40%). In particular, the lower the customer's load factor, the lower the costs allocated by the A&E methodology to that customer, while the allocation will remain the same regardless of when the customer's peak demand occurs.

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<sup>71</sup> Ex. 005, Application, Section 4, pp. 15-17

<sup>72</sup> Ex. 013, Appendix D to the Application, p. 1

<sup>73</sup> Ex. 106, EnCana.AESO-012 (b), *Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen (Catalano, 1981), p. 498

<sup>74</sup> Ex. 126, TCE.AESO-022 (d-e)

<sup>75</sup> Ex. 188, EnCana.AESO-018 (c) Revised

Most interveners, particularly TCE and ADC, were critical of the proposed A&E methodology. TCE filed Appendix E to its evidence as a critique of the A&E methodology. The main problems TCE found with what it considered to be the standard application of an A&E method included:

1. This method has usually arisen to allocate generation costs, and a methodology used for generation is not necessarily warranted for allocating transmission costs.
2. The standard A&E method would assign about 80% of system transmission costs to energy, and the AESO has acknowledged that billing “based totally on usage would provide a very weak signal for customers to manage their load profile.”<sup>76</sup>
3. The standard A&E method assumes an overly simplistic straight line relationship between customer load factors and coincidence with the peaks that drive transmission costs.<sup>77</sup>
4. Implementation of the A&E method requires complex computations.
5. This method has never been widely adopted in utility practice. The NERA report found that for most of the North American utilities surveyed transmission is “classified entirely as demand-related and allocated using 12 CP (FERC’s standard method) or another measure of coincident peak.”<sup>78</sup>

TCE also expressed concerns with the specific A&E methodology proposed by the AESO, including:

1. In its applying the excess component of its A&E method, the AESO intends to use billing demand including ratchets and contract demands, which does not encourage efficient use of the system.
2. Instead of using the system load factor for allocating the average component of the A&E method, the AESO proposes to use the average of the “length-weighted average 240 kV line load factor” for 2004 and 2005 which is 48.6%,<sup>79</sup> which likely to be less stable than the system load factor, leading to rate instability.
3. The proposed use of the “average length weighted 240 kV line load factor” has no known precedent or theoretical underpinning in the context of the average and excess method.<sup>80</sup>

Dr. Rosenberg, on behalf of ADC, summarized the disadvantages of the A&E method in his evidence.<sup>81</sup> Dr Rosenberg stated the A&E method is generally considered unfair to customers that are primarily off peak customers, is considerably more difficult to administer and is usually used in embedded cost of service studies (and not as a rate design tool). He also considered that the A&E method will not encourage off-peak usage and did not recognize the dimension of timing of demands in cost causation, as it is based entirely on average demand and non-coincident demand.

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<sup>76</sup> BR.AESO-002 (a) (iv)

<sup>77</sup> TCE quoted John S Ferguson, in the Public Utilities Fortnightly in September, 1982 (p. 57)

<sup>78</sup> Attachment BR.AESO-001, p. 10

<sup>79</sup> Ex. 005, Application, Section 4, p. 16, lines 24 to 30

<sup>80</sup> Ex. 242, TCE Evidence, Appendix E, p. 3

<sup>81</sup> Ex. 221, ADC Evidence, p. 19

ADC also argued that that the AESO's proposed A&E method was also at variance with NERA's understanding of the method.<sup>82</sup>

EnCana was also critical of the proposed A&E method. It considered that the AESO mischaracterized the Bonbright justification for an A&E method. EnCana submitted that when read in the full context, the Bonbright discourse conveyed that an A&E method is primarily justified as a substitute for the "first and most widely used method," which is the coincident peak responsibility method for recovery of demand-related costs.<sup>83</sup> EnCana also submitted that the Bonbright justification for an A&E method is rooted in circumstances where there is an inability to ascertain the coincidence between individual load and the peak (coincident) system load and therefore an inability to carry-out the coincident peak responsibility method.<sup>84</sup>

EnCana submitted that before adopting the proposed A&E method, it should first be determined whether the AESO has convincingly demonstrated that a coincident peak responsibility method for recovering bulk transmission rates cannot be developed. EnCana maintained that when transmission planners prepare the system for the worst-case load condition, they focus on coincident system peak, coincident regional peaks or near peaks and that there is no evidence to suggest that the AESO cannot measure the contribution of each customer to each of these events.

EnCana also argued<sup>85</sup> that the proposed A&E method is unorthodox and at variance with the methodology as illustrated by the NARUC Cost Allocation Manual.<sup>86</sup>

There was some debate among the parties as to the extent, if any, to which a standard A&E method exists, and if so the nature and extent of the departures from it that are reflected in the Application. The Board agrees with the AESO, that its proposal ought to be assessed on its own merits. The Board, however, does not agree with the AESO that the proposed A&E method results in a reasonable classification and allocation of wires costs.

Implementation of the A&E method would, in the Board's view, involve a substantial change from the status quo, and given the significant and generally well-founded concerns of interveners regarding this method, the Board does not consider that the AESO has adequately justified a change of this nature.

The Board has, in section 4 of this Decision, regarding rate design principles, confirmed that cost causation is a primary factor in rate design. The AESO itself has confirmed that these costs are fixed:

On a very basic level, transmission assets represent by nature a long-term fixed investment. Once planned and built, the cost of the transmission system varies very little based on usage. Its cost should therefore be recovered as a fixed, rather than variable, cost, which would generally lead to classification as a demand-related cost.<sup>87</sup>

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<sup>82</sup> ADC Reply, p. 6, referring to Exhibit 81, NERA report, executive summary, page iii

<sup>83</sup> Bonbright, p. 494-500

<sup>84</sup> Bonbright, p. 498

<sup>85</sup> EnCana Argument, p. 24

<sup>86</sup> EnCana Argument, p. 24 refers to National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, Washington, D.C., (January 1992), pp 49-52 and 81-82.

<sup>87</sup> Ex. 005, Application, Section 4, p. 37

Classifying 48.5% of system transmission system costs as energy related provides a poor price signal to customers to shift their load away from peak hours to reduce demand at the system peak, thereby reducing the need for system expansions and the consequent costs.

For the above reasons the Board rejects the use of the proposed A&E method. The Board finds that transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges.

#### **5.4.2 Consideration of Alternative Classification**

Having rejected the A&E method the Board must now determine an appropriate classification for bulk and local wires costs.

The TCCS filed in the 2005/2006 GTA used a minimum system approach to classify approximately 11% of wires costs as energy related.<sup>88</sup> The TCCS argued that the energy related costs resulted from augmenting the size (diameter) of the wires so as to minimize the cost of losses. In the present case, the TCCU has continued this methodology and its updated results indicate that the use of this approach results in approximately 12% of wires costs, or 18% of bulk and local wires costs, being classified as energy (usage) related.

ADC objected to the use of the minimum system approach. Dr. Rosenberg, on behalf of the ADC, stated that the NARUC manual references a minimum system approach only with respect to the classification of distribution system between demand related costs and customer related costs.<sup>89</sup> Dr. Rosenberg maintained that the actual portion of costs that varied in direct proportion to energy was closer to zero<sup>90</sup> and recommended under cross examination by the Board that the energy classification be set at zero.<sup>91</sup> However, Dr. Rosenberg also went on to say that if the Board chose to retain a usage charge, classifying 18% of bulk costs as energy could be justified as reasonable.<sup>92</sup> Powerex agreed with the arguments of Dr. Rosenberg<sup>93</sup> and also argued against the minimum system approach.

TCE supported the views of ADC and Powerex. It also observed that the Board had directed the AESO to examine its Operations and Maintenance (O&M) costs in future cost of service studies. It suggested that O&M costs comprise a reasonable portion (one quarter to one third) of the total revenue requirements of TFOs. As it is these revenue requirements that form the basis of the wires costs collected by the AESO in its rates, a material change in the classification of these costs could have a marginal effect on the rate design of the AESO. With respect to O&M, TCE submitted that no fixed costs of transmission lines should be allocated on energy since they do not vary with usage.<sup>94</sup>

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<sup>88</sup> Decision 2005-096, p. 18

<sup>89</sup> Ex. 221, ADC Evidence, p. 8

<sup>90</sup> ADC Reply Argument, p. 12

<sup>91</sup> ADC Argument, p. 7 refers to Tr. Vol. 5 pp. 1040-1041

<sup>92</sup> Ex. 221, ADC Evidence, p. 20

<sup>93</sup> Powerex Argument, p. 17

<sup>94</sup> TCE Argument, p. 26

The TCCU indicated that there is insufficient data to properly allocate O&M costs by function, vintage or equipment type. It further stated that in any event, the impact of functionalizing O&M is likely to be small, given the proportion of TFO revenue requirement that consists of O&M, the similar ages of the equipment and the relatively equal amounts of line and substation equipment in the largest cost function (bulk system).<sup>95</sup> Referencing the TCCU, the AESO argued, with respect to O&M costs:

... that given all these factors — OMA costs accounting for about one-quarter to one-third of TFO revenue requirements, all equipment involving a similar mix of vintages, the largest cost function (bulk system) containing relatively equal amounts of line and substation equipment, and the proportion of O&M costs which vary with usage expected to be less than 50% — it is reasonable to expect that the classification of O&M costs would not materially affect the validity of allocated O&M costs in proportion to the underlying cost of facilities.<sup>96</sup>

In Decision 2005-096, the Board directed that 20% of total transmission wires costs be collected on an energy basis.<sup>97</sup> As all POD related costs (which were included in total wires costs) were collected on a customer/demand charge basis, the energy charge had the effect of recovering approximately 35% of bulk and local wires costs on an energy basis.<sup>98</sup>

The results of the TCCU indicate that only 18.5% of bulk costs and 17.5% of local wires costs can be classified as energy related, or only 11% of total transmission wires costs.<sup>99</sup> The TCCU indicated, and the AESO argued, that further research into O&M costs of TFOs will not alter these percentages in a material manner.<sup>100</sup>

The evidence and arguments of the interveners, particularly that of TCE, Powerex and Dr Rosenberg, could justify an energy classification as low as 0%.<sup>101</sup> The Board has in section 5.3.1 of this Decision accepted the results of the TCCU with respect to the classification of wires costs as reasonable. As noted, this only supports a maximum classification of approximately 18% of bulk and local wires costs as energy related. As such, the Board finds that the evidence establishes a zone of reasonableness of 0% to 18% of costs that could potentially be classified as energy related. The Board has also stated in section 4 of this Decision that cost causation must be the primary factor in rate design. The Board finds that the evidence in this case can support a maximum classification of only 18% of bulk and local wires as energy related.<sup>102</sup>

In Decision 2005-09, the Board stated:

However, the Board also considers that a reasonable portion of TFO costs are related to O&M and that a material percentage of these may be energy related. Unfortunately, the impact of this factor does not appear to have been researched in this current study and therefore the Board cannot draw a firm conclusion respecting its impacts on the demand

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<sup>95</sup> Ex. 012, TCCU, pp. 54-56

<sup>96</sup> AESO Argument, p. 21

<sup>97</sup> Decision 2005-96, pp. 21-24 and pp. 26-29

<sup>98</sup> Ex. 006, Application, Schedule 5.10, adding the energy related amounts for bulk and local costs (lines 5 and 6), then dividing by the sum of lines 3 to 6 (total of bulk and local costs), yielding approximately 35%.

<sup>99</sup> Ex. 012, TCCU, p. 53

<sup>100</sup> Ex. 012, TCCU, pp. 54 - 56 and AESO Argument, p. 21

<sup>101</sup> Tr. Vol. 5, pp. 947-948

<sup>102</sup> Including the TCCU, p. 53, testimony of Dr. Rosenberg, Tr. Vol. 5, pp. 1040-1041

charge. Nonetheless, based upon the percentage that O&M expenses comprise of a TFO's revenue requirement, the Board considers that such an analysis would support a reasonable classification of costs as energy related.<sup>103</sup>

The Board considers that a portion of TFO O&M costs are energy related. It is clear from the evidence in this proceeding, however, that this percentage is less than that directed to be used for the 2006 tariff. The AESO has indicated that sufficient information is simply not presently available and even if it was possible to obtain such data, the impact of incorporating such information is likely to be small.<sup>104</sup>

Dr. Rosenberg has suggested that the energy related costs identified in the TCCU be charged to STS customers, on the basis that the costs have been incurred to reduce the cost of losses and STS customers are to bear the cost of all losses. The Board acknowledges that losses are to be paid by generation customers. However, the actual O&M expenditures of the TFOs in question, which are included in the AESO's revenues requirement, relate to wires costs. The Board therefore finds that they must be charged to load customers.

The Board finds that bulk and local wires should both be classified as 18% energy related, the upper end of the zone of reasonableness established by the evidence, and collected on an all hours energy basis as one energy charge. As stated above, the Board considers that a portion of wires costs are energy related. The Board also considers the TCCU to be the best available evidence as to what that portion should be. The remaining 82% of the costs related to bulk and local wires are to be classified as demand related. This is consistent with both the evidence contained in the TCCU, and the principle that rates should reflect cost causation. The Board finds that this will also provide more effective price signals to consumers than will the proposed A&E method.

Rate shock will be dealt with in section 5.9 of this Decision. However, given the evidence of the AESO with respect to bill impacts on a 2005 over 2007 basis<sup>105</sup> and the evidence of Dr. Rosenberg with respect to bill impacts on 2006 over 2007 basis<sup>106</sup> the Board does not consider this decision will have a material impact when compared to the continuation of the "status quo".

The classification and allocation of POD costs will follow in section 5.7 of this Decision. The Board will next address the allocation of bulk and local wires costs classified as demand.

## **5.5 Allocation of Wires Costs**

### **5.5.1 Allocation of Bulk Wires Costs – Demand Portion**

As noted above, the AESO has accepted the hypothesis that there is only a weak or non-existent correlation between peak load and maximum stress on the system. The AESO has concluded that load in every hour is important. Having accepted these propositions, the AESO has rejected CP as an appropriate allocator for bulk system costs and has instead proposed to rebundle bulk and local wires costs and to allocate the portion classified as demand related on the basis of NCP and

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<sup>103</sup> Decision 2005-96, p. 23

<sup>104</sup> Ex. 005, Section 4 of Application, p. 12

<sup>105</sup> Ex. 159, BR.AESO-003(b)

<sup>106</sup> ADC Evidence, Schedule 5, p. 3

to apply a ratchet incorporating contract capacity.<sup>107</sup> In the previous section, the Board determined that the energy portion is to be collected on the basis of an all hours energy charge. In this section, the Board considers the demand portion.

The AESO in argument defended its decision to use NCP to allocate bulk costs,<sup>108</sup> noting the TCCU's investigation of the relationship between loading on individual bulk system transmission lines (as representative of maximum stress) and total AIL found that there was very weak correlation between the two.

In particular, the AESO suggested the lack of bulk line loading coincidence with system peak was clearly illustrated by the peak day profiles for each individual 240 kV line in each month of 2005 and 2004 provided in Appendix D to the Application.<sup>109</sup> The AESO submitted that these graphs demonstrated that the monthly hour of system peak does not reflect maximum loading on individual bulk system transmission lines, and is therefore inappropriate as a basis for recovering the cost of those lines.

The AESO also raised the possibility that a party may be able to avoid the coincident peak on the system and therefore be able to avoid any contribution to the fixed costs of the system. The AESO expressed the view that it would be unjust and unreasonable for those customers who are able to avoid peak hours, but still use the system over many other hours, to largely avoid contributing towards recovery of bulk system costs.<sup>110</sup>

The majority of interveners were critical of the AESO's proposal to use NCP for the allocation of bulk wires costs. The evidence from the AESO customers was that they do not operate in the manner suggested by the AESO.<sup>111</sup>

In its evidence, TCE provided several reasons for rejecting the use of the NCP approach (in favour of a 12 CP method) and maintained that CP was better aligned with how the system was planned.<sup>112</sup>

ADC, IPCAA, Powerex and EnCana all agreed that CP should be used for the allocation of bulk wires costs. Most of their arguments, however, tended to dwell on discrediting the TCCU finding that there was no correlation between line peaking and system stress. In addition to presenting argument on allocating costs of the diverse system using NCP and contract demand,<sup>113</sup> ADC discussed the diversity on the system, noting the following:

Diversity of Load: The bulk system is planned on the basis of a large number of diverse loads (highest amount of diversity) as well as the forecast production level and location of generation. The local system is planned to meet the coincident load of a small number

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<sup>107</sup> Ex. 005, Application, Section 4, pp. 8-12

<sup>108</sup> AESO Argument, pp. 40-41

<sup>109</sup> Ex. 013

<sup>110</sup> AESO Argument, pp. 9

<sup>111</sup> A. Rosenberg (Tr. Vol. 5, p. 973, lines 1 to 18 and refer also to ADC Argument, p. 19); D. Levson (Tr. Vol. 6, p. 1129, line 25 to p. 1130, line 8); Ex 315, CG-DUC/TCE-1 (b) and noting that most loads are predictable and stable and only a few can load shift or suppress their load; Exhibit 242, TCE Evidence, p. 18, lines 28 to 30; Tr. Vol. 5, pp. 937-938 and pp. 1015-1017.

<sup>112</sup> Ex. 242, TCE Evidence, p. 2, 13

<sup>113</sup> ADC Argument, pp. 14-15

of diverse loads and the point of delivery is planned to meet the load of one point of delivery substation (no diversity).<sup>114</sup>

Extensive submissions were received regarding the classification of bulk wire costs. The Board rejects the AESO's proposal to allocate bulk wires costs on the basis of NCP. Additionally, The Board finds that the bulk and local wires components of the DTS rate are to remain unbundled.

The Board has earlier found that system peaks are more important than load in every hour in the planning of the transmission system. The Board concurs with the evidence of TCE and ADC and finds that there is a reasonable degree of diversity on the bulk system. The Board accepts the evidence of PS Technologies, in the TCCU that the greatest degree of diversity exists on the bulk system:

At the POD, the coincident load to maximum stress is the same as the maximum demand (ignoring seasonal changes in thermal capacity). The further that you move from the POD to the Local System and into the Bulk System, the more diversity there is between loads and the diversity increases the difference between coincident load to maximum stress and maximum demand. If there were no diversity, then maximum demand and coincident load to maximum stress would occur at the same time and both parameters would be appropriate to classify the demand related costs.<sup>115</sup>

The Board also concurs with the evidence of Dr. Rosenberg noted above that NCP and contract demand do not recognize this diversity and are not appropriate allocation factors for bulk costs.

The Board also accepts the evidence of TCE<sup>116</sup> and ADC<sup>117</sup> that CP is better aligned with how the bulk system is planned.

The AESO has stated that it is unjust and unreasonable for a party to avoid any contribution to the costs of the bulk system by virtue of their ability to avoid the peak hour each month. However, the Board finds no evidence has been provided that such a customer exists on the system. The Board concurs with the evidence of ADC and TCE<sup>118</sup> as to how the CP method actually works; to incent customers to shift load to non peak hours, not necessarily avoid the peak entirely.

The Board is interested in the real price signal being received by real customers. With respect to this, Mr. World, a witness for the ADC, was the only customer to present testimony as to the price signal being received by customers and the actions customers are taking as a result of the signal being sent by the use of the CP method.<sup>119</sup> The Board finds the testimony of Mr. World to be both credible and instructive. Clearly it is not possible for a customer to generally simply turn the power off and completely avoid the hour of system peak as the AESO has suggested above. The Board acknowledges that the primary goal may be to reduce energy costs. However, it is equally clear that customers are already motivated to shift load to achieve a flatter load profile,

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<sup>114</sup> Transmission Cost Causation Study 2005, p. 18

<sup>115</sup> Ex. 012, TCCU, p. 33

<sup>116</sup> Ex. 242, TCE Evidence, p. 13

<sup>117</sup> Ex. 221, ADC Evidence, p. 5 refers to TCCS, p. 18

<sup>118</sup> A. Rosenberg (Tr. Vol. 5, p. 973, lines 1 to 18 and refer also to ADC Argument, p. 19), D. Levson (Tr. Vol. 6, p. 1129, line 25 to p. 1130, line 8)

<sup>119</sup> Tr. Vol. 5, pp. 937-938 and pp. 1015-1017

which is exactly the behaviour the AESO claims it wishes to induce.<sup>120</sup> The Board also notes that the use of the 12 CP method would be more consistent with past Board approved rate design.<sup>121</sup> For the above reasons the Board rejects the use of NCP as the allocator for bulk system costs.

The AESO is directed to continue to unbundle bulk and local wires costs and to use the 12 CP method as the allocator for collecting the demand portion of bulk wires costs.

### 5.5.2 Allocation of Local Wires Costs – Demand Portion

The AESO proposed to continue the present rate design of allocating demand related wires local costs on the basis of NCP, with the use of a contract demand ratchet.

EnCana,<sup>122</sup> TCE,<sup>123</sup> and IPCAA<sup>124</sup> objected to the use of a ratchet only with respect to bulk wires costs. The ADC did not object to the use of NCP to allocate local wires costs,<sup>125</sup> although it did object to applying the ratchet to local wires costs. In his evidence,<sup>126</sup> Dr. Rosenberg stated that he had only seen two possible rationales for ratchets – one being to allocate specific costs to a single customer, the other being to collect costs from a seasonal customer.

The Board disagrees with Dr. Rosenberg with respect to not utilizing a ratchet in the collection of local wires costs. Dr. Rosenberg's evidence specifically mentions bulk costs and that the reference to the NERA Report<sup>127</sup> quoted by Dr. Rosenberg also refers only to bulk costs.

The Board considers there to be considerably less diversity on the local system than the bulk system. The Board finds that the use of a ratchet at the local system level is a fair and efficient means to ensure recovery of those fixed costs caused by the relatively few, non-diverse customers present at any point on the local system.

The Board therefore directs the AESO to continue the use of NCP, together with the current ratchet, for purposes of allocating and collecting the demand portion of local system wires costs.

## 5.6 Allocation of Ancillary Services Costs

In the Application, the AESO stated that it has not proposed any changes to the classification of ancillary services costs from that approved in Decision 2005-096, after extensive debate.

However, ancillary services costs have been presented in a slightly different manner in the AESO's 2007 revenue requirement. Specifically, costs which were previously identified as Generator Remedial Action Scheme (GRAS) costs now have Brazeau Fast Ramp costs separately identified. Both Brazeau Fast Ramp and the remaining GRAS costs continue to be classified as varying usage-related costs.

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<sup>120</sup> ADC-AESO-6, "The AESO considers that .....customers should avoid demand peaks and should strive for as flat a load profile as practical."

<sup>121</sup> Most recently Decision 2005-096

<sup>122</sup> EnCana Argument, p. 21

<sup>123</sup> TCE Argument, p. 17

<sup>124</sup> IPCAA Argument, pp. 5-6

<sup>125</sup> Ex. 221, ADC Evidence, p. 42

<sup>126</sup> Ex. 221, ADC Evidence, p. 39

<sup>127</sup> Ex. 081, Attachment to BR.AESO-1, NERA Report, p. 17

No party raised concerns with the treatment of ancillary service costs contained in the Application. Subject to such determinations as the Board makes elsewhere in this Decision and subject to such adjustments that may be made in the Article 11 Proceeding to interim payments made under Article 11, the AESO's proposed treatment is approved as filed.

## 5.7 DTS Point of Delivery (POD) Costs and Charges

### 5.7.1 DTS POD Costs and Charges Overview

In section 4.3.4 of the Application, the AESO noted that in Decision 2005-096, the Board directed the AESO to use a cost-based approach to set the maximum investment formula to be used within the AESO's customer contribution policy.

Given that the maximum investment formula derived by the AESO in response to the Board's direction reflected the costs of POD facilities, the AESO determined that the cost function used to derive its proposed maximum investment formula could also be used to classify POD costs for DTS rate design purposes. Accordingly, the AESO developed its proposed classification of the POD portion of the DTS rate based on its proposed POD cost function<sup>128</sup> as described below:

**Table 2. Original AESO POD Cost Classification Summary**

Cost Component	Customer	≤ 7.5 MW	> 7.5 MW	Total
Unit Cost (\$ 000 000)	\$0.947	\$0.621	\$0.154	
Billing Determinant	4,854.4	32,514.8	82,133.3	
Total Costs (\$ 000 000)	\$4,596.5	\$20,203.8	\$12,665.6	\$37,465.8
Classification	12.3%	53.9%	33.8%	100.0%

Source: Application Table 4.3.6 (Section 4, p. 14)

The AESO revised its proposed classification in its argument submission to include a third tier for loads over 50 MWs, as summarized in the following table:

**Table 3. Revised AESO POD Cost Classification Summary**

Cost Component	Customer	≤ 7.5 MW	> 7.5 ≤ 50 MW	> 50 MW	Total
Unit Cost (\$ 000 000)	\$0.947	\$0.621	\$0.154	\$0.047	
Billing Determinant	4,854.4	32,514.8	65,478.3	16,655.0	
Total Costs (\$ 000 000)	\$4,596.5	\$20,203.8	\$10,083.7	\$782.8	\$35,655.3
Classification	12.9%	56.6%	28.8%	2.2%	100.0%

Source: AESO Argument Table 3.4.1 (p. 44 of 99)

In reply, parties took issue with the substance of the classification proposed in the AESO's argument.

<sup>128</sup> In light of the AESO's proposal to use the same cost based function as the basis for both its maximum investment formula and its proposed DTS POD charge rate design, for ease of reference, the Board will refer to the underlying relationship between average POD costs and POD capacity as the "POD Cost function". In adopting this convention, the Board acknowledges the views of some parties that cost functions used for contribution policy purposes and rate design purposes should be different. The Board addresses this issue in section 5.7.3 of the Decision.

After evaluating the information on the record, Board staff developed an alternative POD cost function using the curve estimation functions used by the AESO in its Argument to determine the slope of its proposed POD cost function for PODs larger than 50 MW. Board staff considered whether the use of the non-linear curve functions considered by the AESO could be used to determine a continuous cost function for all sizes of PODs.

Board staff used the 30 greenfield data points, and augmented this data with the 13 data points available below 7.5 MW and the five data points available above 50 MW. This is the same 48 point data set used by the AESO in its final proposed cost function. The AESO used the 30 POD greenfield dataset in conjunction with the 13 TCCS dataset PODs below 7.5 MW to determine the first two tiers of its proposed POD cost function. The AESO used a 96 POD subset of the 109 POD TCCS dataset to determine the slope of its proposed POD cost function above 50 MW.<sup>129</sup>

After observing that a power function provided the best overall fit to the 48 point data, Board staff then developed a series of linear equations, to approximate this curve. The linear equations were based on the calculated power function (or y-axis) values associated with the 0.10MW (first data point), 7.5MW, 17MW, 40MW, and 122.8MW data points (last data point).

By letter dated October 25, 2007, the Board invited comments and reply from parties on the cost function developed by Board staff. The Board received comments and reply from numerous parties.<sup>130</sup> The Board also received responses to information requests posed to the AESO from the Board regarding alternate cost functions developed by the AESO during the comment and reply process. DUC also developed alternate cost functions during this process.

Throughout this proceeding, parties provided extensive and wide ranging evidence on the appropriateness of the POD charge component of the DTS rate design. The Board considers that the submissions relating to the POD charge generally fell into the following major subject areas:

- Board Directions Regarding POD Cost Classification;
- Alignment of POD Charge and Contribution Policy Cost Functions;
- POD Cost Economies of Scale;
- POD Cost Function Dataset;
- Statistical Fit of POD Cost Function;
- Parameters of POD Cost Function;
- Other POD Charge Related Issues

The Board addresses each of the above issues in the following sections of this Decision. In summary, in the remainder of this section 5.7 of the Decision, the Board has found that:

- the AESO has investigated POD costs as required by Decisions 2005-096 and [2005-132](#);<sup>131</sup>

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<sup>129</sup> AESO Argument, p. 75

<sup>130</sup> The AESO, DUC, ASBG-PGA, AE, PPGA, CCA, PICA, ADC, Fortis, and IPCAA provided comments on the alternate cost function.

<sup>131</sup> Decision 2005-132 - Alberta Electric System Operator (AESO) Review and Variation of Customer Related POD Charge (Application No. 1420890) (Released: December 6, 2005)

- it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO's contribution policy;
- the impact of economies of scale on POD costs is significant as capacity increases and is to be reflected in the POD cost function and design of the POD charge;
- it is appropriate to use the best available data to determine the POD cost function for the purposes of both the POD charge and the AESO's contribution policy;
- the statistical fit of the POD cost function approved by the Board in section 5.7.7 of this Decision was sufficient to support its use for both POD charge and contribution policy purposes;
- a non-linear function best describes the of POD cost economies of scale;

Based on the evidence filed by the parties, the Board approves a multi-tiered linear function, as described in the remainder of section 5.7 of this Decision that reflects these findings.

While section 5.7 of the Decision considers the POD charge component of Rate DTS, it is evident that a large part of the POD charge submissions related to the appropriateness of the POD cost function proposed by the AESO for the purpose of establishing both the POD charge as well as for the maximum investment function under the customer contribution policy. Accordingly, as appropriate, the Board has taken into account submissions received on the POD cost function in relation to the customer contribution policy within this section of the Decision.

### 5.7.2 Board Directions Regarding POD Cost Classification

In section 4.3.4 of the Application, the AESO noted that Decision 2005-096 established that cost is the appropriate basis for the maximum investment function used within the AESO's customer contribution policy. In response to Direction 13A<sup>132</sup> of Decision 2005-096 and after analyzing additional data, the AESO proposed the following cost function for its maximum investment function set out in section 6 of the Application:<sup>133</sup>

$$\begin{aligned} \text{Recommended Cost} &= \$0.947 \text{ million} \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW}) \end{aligned}$$

The AESO submitted that the Board had been clear that the investment function and the function for the POD charge were to be cost based, and that it had developed its proposed POD charge in compliance with the Board's direction.<sup>134</sup> In its rebuttal evidence, the AESO noted that several references in Decision 2005-096 suggested that cost should underlie the development of both the investment function and the design of the DTS rate.<sup>135</sup>

The AESO's interpretation of Board directions related to POD costs, as used in the development its proposed DTS POD charge, generated argument submissions by several parties.

<sup>132</sup> As discussed in section 9.1 of this Decision, the Board has adopted a convention for numbering Board directions based on the AESO's refile application (Application #1420890) in relation to Decision 2005-096, as approved by the Board in Decision 2005-131

<sup>133</sup> Ex. 007, Application, Section 6, p. 22

<sup>134</sup> AESO Argument, pp. 69-70

<sup>135</sup> Ex. 347, AESO Rebuttal Evidence, pp. 2-3, citing Decision 2005-096, pages 17, 26, 27, 56

PPGA submitted that acceptance of AESO data for the purposes of determining the AESO's investment function should not imply acceptance of that data for POD charge rate design purposes. It also submitted that whereas the POD charge is based on embedded costs, the AESO's investment policy is forward looking.<sup>136</sup> PPGA submitted that these two purposes are different. It further questioned the accuracy of the data set used by the AESO and DUC in establishing their POD charge proposals. PPGA noted that while the Board had directed the AESO to have a cost based POD function, the Board did not require the AESO to link the POD and investment functions.

DUC noted that the AESO's TCCS in the 2006 AESO tariff proceeding indicated that POD costs contained a large fixed component, which led to the Board's approval in Decision 2005-096 of a monthly charge of \$21,899.

DUC submitted that the Board's directions in Decision 2005-096 anticipated that the AESO's interconnection cost function would exhibit significant economies of scale and could, as a result, be non-linear in nature. DUC further submitted that, in response to smaller sized customers that had expressed concern about the large price increase resulting from the large fixed POD charge approved in Decision 2005-096, the Board provided relief to customers under five MW in size. DUC referred to Decision 2005-132, in which the Board directed the AESO to perform further analysis on POD costs and to file the analysis with its 2007 GTA. DUC submitted that while the AESO had, in large part, responded to the Board's directions, the AESO's investment function, POD charges, primary service credits, and maximum investment amounts should be enhanced to better reflect the cost causation for larger PODs.

While parties focused primarily on Board directions arising from Decision 2005-096 and, to a lesser extent Decision 2005-132, a key Board direction leading to the eventual establishment of a POD charge arose from Decision 2001-32.<sup>137</sup> In that Decision, the Board directed the predecessor of the AESO to carry out a cost of service study to be used in developing the tariff structure for the 2003 GTA.<sup>138</sup> This direction was fulfilled by the AESO through preparation of the TCCS filed in its 2005-2006 GTA. The Board was persuaded by the TCCS that POD costs amounted to approximately 24% of total costs<sup>139</sup> and that POD costs as identified in the TCCS should be recovered by way of a customer-related charge.<sup>140</sup>

As pointed out by the PPGA, Direction 13A from Decision 2005-096 related to the maximum investment formula to be used in conjunction with the AESO's customer contribution policy. It did not relate to the POD charge portion of the DTS rate.

Decision 2005-132 arose from a Board initiated application to review and vary the impacts of the POD charge approved in Decision 2005-096 on the smallest AESO customers. In Decision 2005-132 the Board approved a temporary exception from the finding in Decision 2005-096 that cost causation should be the primary determinant of the POD charge design. However, as indicated in Decision 2005-132, the redesigned POD charge set out in that decision was intended to be a

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<sup>136</sup> PPGA Argument, p. 21

<sup>137</sup> Decision 2001-32 ESBI Alberta Ltd. 2001 General Tariff Application Part H: Phase II Matters (Application 2000135) (Released: May 2, 2001)

<sup>138</sup> Decision 2001-32 direction 21 (p. 215)

<sup>139</sup> Decision 2005-096, p. 28

<sup>140</sup> Decision 2005-096, p. 29

“stop gap” measure to apply until further and more detailed cost causation research could be completed.<sup>141</sup> Therefore, after having provided rate relief to small customers for 2006, the Board provided clear directions to the AESO in Decision 2005-132 to undertake additional analysis of POD costs to be filed with the AESO’s 2007 GTA. Specifically, the Board directed the AESO to collect information on the items comprising POD costs, the costs of PODs serving smaller loads as compared to those serving larger loads, whether a reasonable cost breakpoint exists between smaller and larger PODs, and the additional relief, if any, that should be offered to customers who have paid for their own transformation equipment.<sup>142</sup>

The direction from Decision 2005-132 is a reinforcement of the Board’s general desire that cost causation should, for the most part, drive the AESO’s DTS rate design. The Board deals with the question of how well the AESO’s proposed POD cost function reflects the causation of costs in section 5.7.7 of this Decision. The Board considers that the AESO has appropriately investigated POD costs as required by Decisions 2005-096 and 2005-132.

The Board considers that its finding that cost causation is the rate design criterion to be afforded the most weight applies to the POD charge and not solely to the rate design for recovering bulk and local system costs.

### **5.7.3 Alignment of POD Charge and Contribution Policy Cost Functions**

The AESO noted in section 4.3.4 of the Application that Direction 13A from Decision 2005-096 required it to analyze additional data for the purposes of recommending a revised maximum investment function. The AESO suggested that since the underlying cost function used to develop its proposed maximum investment function reflects costs caused by a customer interconnection at a POD, that cost function should also be used to classify POD costs.<sup>143</sup>

A number of parties, for example, the Consumers Coalition of Alberta and the Public Institutional Consumers of Alberta (CCA/PICA) and PPGA made submissions in argument, disagreeing with the AESO’s decision to use the same underlying cost function as the basis for both its maximum investment function under the contribution policy and its classification of POD costs through its proposed POD charge.

The AESO disagreed. It submitted that as both the POD charge and the investment function present price signals which can only affect future customer behaviour, but not cause past costs to be avoided, using a common POD cost function for both purposes would be appropriate. The AESO considered that its proposed POD cost function should establish the structure or shape (i.e. the relationship between fixed (\$/month) and demand (\$/MW) components) of the function.

PPGA noted that whereas the AESO presented the TCCS in its 2005-2006 GTA, the AESO did not recommend using that data in support of a POD charge to be levied on customers. While the notion of linking the investment and POD charge cost functions might appear rational, PPGA submitted that the purposes of the POD charge and the investment function are very different. Whereas the investment function deals with forward looking decisions, the POD charge is an allocation of the historical net book cost of radial lines and substations to all PODs. Given the

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<sup>141</sup> Decision 2005-132, p. 4

<sup>142</sup> Decision 2005-132, p. 4

<sup>143</sup> Ex. 005, Section 4.3.4 of the Application

consequences on smaller customers from a dramatic shift in POD costs to them, PPGA submitted that the AESO has not provided adequate evidence that relative proportions (i.e. Y-intercept and slopes) from the investment function were representative of the all POD data.

DUC submitted that the Board clearly articulated in Decision 2005-096 that cost causation was the primary rate design criteria. DUC further submitted that the cost causation principle dictates that all components of the rate design need to reflect cost causation. In particular, it considered that each of the DTS rate POD charges, PSC rates and maximum investment amounts should be aligned and derived from the interconnection cost function which reflects cost causation for POD interconnections. Accordingly, DUC agreed with the AESO that DTS POD charges and maximum investment amounts should be aligned, but disagreed with the AESO decision not to bring PSC rates into alignment with POD charges.

DUC submitted that a fundamental design consideration for the POD charge is whether it is intended to recover costs based on historical cost causation or future cost causation. DUC noted that this question is generally not relevant to most rate design exercises since future costs are recovered in the same manner as historical costs. However, it noted that the AESO's current policy is to only invest in a single transformer for new customer connections, which DUC submitted was different than the historical practice of providing more than one transformer for larger services. Notwithstanding the change in the AESO's policies regarding transformer investment, DUC submitted that its evidence demonstrated that DUC's proposed interconnection cost function was appropriate from a historical and future cost causation perspective.<sup>144</sup>

The Board considers that it is appropriate that, to the extent possible, the POD charge component of Rate DTS reflect cost causation. Accordingly, it is necessary to use a cost function that provides the best possible representation of the manner in which POD costs are caused.

The Board considers that an assessment of the AESO's proposed POD cost function proposed to be used in determining the POD charge component of Rate DTS must reflect the fact that the POD cost function is used only to allocate costs previously functionalized as POD related costs in the TCCU. The Board considers that a POD cost function derived for contribution policy purposes appropriately describes the fixed and variable proportions of TFO costs functionalized as POD related as between customers of different sizes because, as described below, the Board is unable to find that underlying shape of the average cost would be materially different.

While the Board acknowledges the observation of the PPGA that the Board's directions in Decision 2005-096 did not specifically direct the AESO to use a cost function to derive a maximum investment function for the purposes of developing a POD charge, the Board strongly agrees with the AESO that the contribution policy investment function and the POD charge cost function are both representative of the same set of underlying costs. As such, the Board finds that it is reasonable for the AESO to have proposed that the same underlying average cost function be used for both of these two purposes.

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<sup>144</sup> A footnote at p. 7 of DUC's argument references DUC argument at pp. 18-19. At pp. 18-19, DUC explains that a recommended "third tier" in its proposed cost function using data provided in the AESO's rebuttal evidence was based on five data points. Of the five data points, DUC noted that 4 of the data points described the cost of four PODs served by more than one transformer, two PODs that are served by more than one transmission line and one POD that is served at 245kV.

The PPGA's submissions placed considerable focus on differences between embedded historical costs and a forward looking POD cost function devised to set maximum investment allowances under the customer contribution policy. However, the PPGA did not substantiate its claim. As a result, the Board is unable to conclude that the shape of a historical POD cost function and a forward looking POD cost function would be materially different.

Given that the maximum investment function was designed to reflect the "one-line, one-transformer" standard, whereas existing PODs may have more than one transformer and/or lines, it was incumbent on the Board to assess whether this consideration would cause the underlying shape of a cost function for POD charge purposes to be different from a cost function reflecting only the cost of standard facilities for the purposes of the contribution policy's maximum investment function.

However, DUC observed that it is generally at larger PODs where additional transformers are more likely to be deemed desirable.<sup>145</sup> Thus, the Board considers that any potential distortion of the cost causation principle arising from the use of a POD cost function based on only standard facility costs tend to occur in larger rather than smaller PODs, since multiple transformers tend to exist only in larger PODs. As noted by DUC in argument, four of the five historical cost data points (supplied by the AESO) represented PODs with more than one transformer.<sup>146</sup> Therefore, as the Board has used the cost data for the five PODs referred to by DUC for its approved POD cost function, the underlying shape of the cost function for POD charge purposes does not differ from the POD cost function used for the purposes of the contribution policy's maximum investment function. Thus, the Board finds that it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO's contribution policy.<sup>147</sup>

#### 5.7.4 POD Cost Economies of Scale

In Appendix F to the Application, the AESO indicated that it had analyzed data collected to develop its proposed interconnection cost function to determine whether the data exhibited any significant economies of scale, whether the relationship between contract capacity and cost was linear or non-linear in nature and/or if any relationships other than contract capacity and cost existed. Appendix F also noted that examination of cost data for 30 greenfield interconnection projects had established that a linear function appropriately represented the relationship between average cost and capacity. The AESO noted, however, that an analysis of subsets of the greenfield data did not improve the  $R^2$  of the regression lines as compared to the regression line produced from all 30 data points. The AESO also noted that non-linear regression analysis was also performed but did not provide better regression coefficients than the linear analysis. Accordingly, the AESO considered that a single straight-line average cost function provided the best representation of the average cost of the 30 greenfield projects.

The extent to which POD cost data exhibited economies of scale was discussed more extensively in the evidence of DUC. In its evidence, DUC submitted that the AESO's analysis did not reflect

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<sup>145</sup> Ex. 229, DUC Evidence, p. 30

<sup>146</sup> DUC Argument, p 7 and 18-19, citing AESO Rebuttal Evidence pp. 1-2

<sup>147</sup> DUC Argument, p 7 refers to Exhibit 305 – 80% of PODS above 40MW have more than 1 transformer.

the significant economies of scale present in PODs over 40 MW. DUC submitted that there is not a linear correlation between substation costs and DTS capacity for larger substations.<sup>148</sup>

DUC anticipated that while substations would have some level of fixed costs and would have some incremental costs related to size, substation costs did not continue to increase at the same rate with size. In particular, DUC noted that evidence filed by TCE in the AESO's 2005-2006 GTA indicated that both transmission line and substation costs exhibited economies of scale.<sup>149</sup>

In its argument, PPGA proposed a POD charge comprised of a fixed monthly charge and a uniform per MW rate. PPGA submitted that the AESO's proposed POD cost function would lead to its members receiving a proportionately larger increase in rates as compared to larger load customers who receive the benefit of economies of scale for certain components of the POD charge. PPGA submitted that there are numerous factors which impact the determination of the POD charge that do not result in decreasing unit costs based solely on achieving economies of scale.

PPGA submitted that the POD charge evidence of DUC focused solely on economies of scale for substations but ignored other factors such as the cost of radial lines and other considerations that impact overall POD costs. In addition, PPGA submitted that DUC made several acknowledgements which PPGA considered to counteract the tendency of PODs to exhibit economies of scale. PPGA submitted that DUC's view ignored parameters such as line length, terrain, rural as compared to urban locations; telecommunication needs, voltage level, conductor size and structure types. Accordingly, PPGA submitted that not only were there no economies of scale associated with many factors that influence POD costs, many aspects of POD costs actually exhibit diseconomies of scale since costs increase as POD size increases.

In argument, and in recognition of DUC's evidence, the AESO proposed an additional tier for its POD cost function to reflect an incremental cost of \$47,000/MW for interconnections above 50 MWs.<sup>150</sup> However, the AESO submitted that whereas DUC had indicated that the primary cost driver above 40 MWs should be limited to transformation, DUC had failed to account for factors that create additional complexity and cost when capacity exceeds 40 MWs.

In response to an information request, DUC provided a helpful conceptual explanation for the tendency of the average cost of PODs to exhibit economies of scale with increases in POD capacity.<sup>151</sup> In that response, DUC indicated that the major cost components of a substation (such as installation costs, land, ground grid, support structures, switches and communication/protection equipment) are either fixed or exhibit limited economies of scale. However, DUC indicated that once the base substation equipment is installed, increasingly large substations generally require larger transformers only to increase capacity. DUC's evidence provided support for the notion that transformer costs increase at a decreasing rate with capacity increases.<sup>152</sup> The Board finds that DUC's evidence on the drivers of POD costs provided compelling evidence of substantial economies of scale.

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<sup>148</sup> Ex 229, DUC Evidence, pp 12- 13 citing Application Appendix G spreadsheet, tab Subs and DUC POD PSC evidence App G revised.xls, tab subs chart.

<sup>149</sup> Ex. 229, DUC Evidence, p. 14, citing Exhibits 23-010 and 02-019-001 from AESO 2005-2006 GTA proceeding

<sup>150</sup> AESO Argument, p. 77 of 99

<sup>151</sup> Ex. 306, CG-DUC-1(c)

<sup>152</sup> Ex. 229, DUC Evidence pp. 13-16

PPGA expressed the view that POD facilities exhibit increasing economies of scale due to the minimum y-intercept component of POD costs making a smaller portion of the cost of larger PODs.<sup>153</sup> The Board agrees that fixed costs are an important component of POD cost economies of scale. This is also reflected in the conceptual explanation of the drivers of economies of scale provided by DUC.<sup>154</sup> However, the Board is not persuaded by the assertions of the AESO and PPGA that diseconomies of scale occur that to such an extent as to offset the contributors to economies of scale described by DUC.

In this regard, the PPGA panel filed an extract from the tariff of SaskPower with its opening statement<sup>155</sup> with the apparent intention of demonstrating diseconomies of scale. However, the Board considers that this claim was effectively countered by the DUC panel which noted that the increase in charges with size in the SaskPower tariff extract reflects the fact that SaskPower customers generally own their substations but must use metering equipment supplied by the utility.<sup>156</sup> PPGA suggested that the cost of responding to landowner opposition may increase as the POD cost size increases.<sup>157</sup> The Board also considers that PPGA did not provide a persuasive explanation of why the cost of responding to landowner opposition would vary with the size of a new interconnection, nor did it provide supporting evidence demonstrating this claim.

The Board agrees with DUC that the average cost of transmission interconnections will exhibit significant economies of scale with increasing capacity. The Board further concludes based on the evidence provided by DUC that a POD cost function expressed as dollars per MW should be non-linear in shape in recognition that certain components of POD costs (most notably the cost of transformers) tend to increase at a decreasing rate with the capacity of the interconnection.

### 5.7.5 POD Cost Function Dataset

In section 4.3.4 of the Application, the AESO proposed a POD cost function primarily based on a detailed examination of 30 greenfield projects built between 1999 and 2006 representing 516.7 MW of DTS capacity and total project costs of \$213.2 million. Linear regression analysis was used to determine the average cost function. As no projects less than 7.5 MWs were included in the 30 project dataset, the AESO used a small subset of POD cost information drawn from the TCCS to determine a cost function for smaller projects. The AESO recognized that the POD cost classification used in its contribution policy study<sup>158</sup> was significantly different from the minimum intercept analysis performed for the TCCS. However, the AESO submitted that its proposed classification was appropriate because it recognized that a different cost function would be appropriate for smaller projects.

DUC generally supported the AESO's use of regression analysis on the 30 POD greenfield dataset as augmented to include the 13 small project dataset as an appropriate method for developing POD charges.<sup>159</sup> DUC submitted, however, that the AESO's analysis should have

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<sup>153</sup> Ex. 331, IPCAA.PPGA-1

<sup>154</sup> Ex. 306, CG-DUC-1(c)

<sup>155</sup> Ex. H-029

<sup>156</sup> Tr. Vol. 6, pp. 1319-1323

<sup>157</sup> Tr. Vol. 6, p. 1313

<sup>158</sup> Ex. 015, Appendix F to the Application

<sup>159</sup> DUC Argument, pp. 14-16

considered the lower unit interconnection costs of large PODs. The Board agrees with DUC that economies of scale for large PODs should be reflected in the POD cost function.<sup>160</sup>

PPGA expressed a number of concerns with the POD cost function data set analyzed by the AESO.<sup>161</sup> While the PPGA highlighted that the data used by the AESO was not optimal, the Board considers that the AESO used the best POD cost data available. The Board also considers that the PPGA's evidence failed to establish that the all POD data was superior or even adequate for establishing a POD cost function for either the POD charge or the AESO's contribution policy's maximum investment function. Even if the Board was to have found that the AESO's dataset is inadequate, it does not follow that the PPGA's approaches are adequate. Nor does it follow that the status quo is preferable.

Another key theme of the PPGA's criticisms was that the greenfield dataset used to analyze POD costs was collected for a different purpose (to comply with a Board direction related to the contribution policy), not for the purpose of refining the POD charge component of Rate DTS. PPGA submitted that the analysis of POD costs for contribution policy purposes is focused on cost causation looking forward, and that this looking forward orientation is not appropriate for determining the allocation of embedded POD costs.<sup>162</sup> The Board does not agree. While rate design entails recovery of the revenue requirement, and thus recovery of embedded costs, the Board considers that cost allocation should also reflect the manner in which costs are expected to be caused in the future. Accordingly, as the goals of POD charge design and customer contribution investment function design are not in conflict, the Board finds that the largely unverifiable all POD dataset (or a subset of that data) is not inherently superior for POD charge purposes than the greenfield dataset used by the AESO.

To the extent possible, the POD cost function should endeavor to represent the functional relationship between the full DTS capacity of the POD and the full cost of constructing a complete POD. Thus, one key advantage of the greenfield dataset is the significant effort devoted by the AESO to ensure that the datapoints are comparable to one another. In this regard, while the AESO's discussion in Appendix F of the Application is specifically related to a 13 POD subset of the 109 data points for which vintage could be established, the comparability issues identified by the AESO in Appendix F would apply to all data derived from the TCCS. The Board considers that the issues addressed by the AESO with respect to the greenfield data are generally of equal or greater concern in respect of potential the use of the 109 POD subset of the all POD data for POD cost function determination purposes.<sup>163</sup>

In order to be useable for the purposes of designing a POD cost function, the Board must have confidence that all of the data points are reflective of comparable circumstances. However, as there is no way to verify whether the 109 POD dataset data points are comparable to one another, the Board concludes that the greenfield dataset is the only available POD cost dataset that has been subject to sufficient analysis to form a reliable basis for determining a cost causation function.

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<sup>160</sup> DUC Argument, p. 16

<sup>161</sup> PPGA Argument, pp. 10-11

<sup>162</sup> PPGA Argument, p. 16

<sup>163</sup> Ex. 015, Application, Appendix F, p. 20

Using 13 all POD dataset data points to represent PODs with capacities below 7.5 MWs and an additional five all POD dataset data points to represent PODs with capacities greater than 43.2 MWs raises issues with respect to its comparability with the greenfield dataset. However, the Board finds these additional data points are the best available POD cost data for projects in these contract capacity ranges. Moreover, since the Board is strongly persuaded that the relationship between POD costs and contract capacity will exhibit economies of scale, the Board considers that a much more significant distortion of the POD cost function would occur if these data points were to be excluded than any potential for distortion that may be caused by incompatibilities with the greenfield data. Thus, in section 5.7.7 below, the Board uses this augmented 48 POD dataset as the basis for the POD cost function approved by the Board.

### 5.7.6 Statistical Analysis of POD Cost Function

In section 6.5.3 of the Application, the AESO stated that it had conducted extensive stakeholder discussion to fulfill the obligations arising from Direction 13A of Decision 2005-096. The AESO noted that it had performed both linear and non-linear regression analysis on the greenfield POD data but that it had determined that a simple linear function provided the best representation of the cost of the 30 greenfield projects. In addition, the AESO indicated that it had examined whether projects of different sizes within the greenfield project dataset exhibited different cost functions by performing statistical analysis on subsets of the 30 project data. The AESO noted that this subset analysis did not produce a regression coefficient greater than the 0.26 level obtained through regression analysis of the entire 30 POD greenfield data set.

A number of parties made submissions regarding the dispersion of the POD cost data and the adequacy of the  $R^2$  values obtained through regression analysis on that data.

The Board considers that the comparatively low  $R^2$  values reflect the fact that factors unrelated to a POD's DTS contract capacity will have a significant impact on the cost of specific PODs. In particular, there is evidence that transmission line costs associated with specific PODs are generally not strongly related to the capacity of the POD.<sup>164</sup> As a result, it is understandable that the POD data could exhibit significant dispersion. It is therefore understandable that a statistically derived dollars per MW POD cost function would not necessarily exhibit high  $R^2$  values.

While the statistical fit may not be high, the Board does not consider that statistical analysis should be discarded solely on the basis that  $R^2$  values fall in the lower range. All things equal, the Board considers that a significantly higher  $R^2$  value is generally preferable to a function with a lower  $R^2$  value as long as the resulting POD cost function appears to reasonably reflect underlying cost relationships such as the effects of economies of scale described in section 5.7.4 above.

### 5.7.7 Parameters of POD Cost Function

The AESO initially proposed a POD cost function consisting of a y-intercept of \$0.947 million and two linear functions tiers with a first tier slope of \$0.621 million per MW to 7.5 MWs and a second tier slope of \$0.154 million per MW beyond the 7.5 MW breakpoint.<sup>165</sup> However, in

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<sup>164</sup> Ex. 005, Application Section 4.5.2, p. 18

<sup>165</sup> Ex. 007, Application Section 6.5.3, p. 22

section 4.1.7 of its argument, the AESO amended its proposed POD cost function to add an additional breakpoint and additional tier beyond 50 MW. As discussed above in section 5.7.1, a proposed POD cost function was devised by Board staff from the evidence filed by the parties and was circulated for comment in Board correspondence dated October 25, 2007. The AESO and several interveners submitted comments on the POD cost function devised by Board staff.

The AESO submitted in its argument that in order to consider the impact of large project costs within its revised POD cost function, it had incorporated cost data from 109 interconnection projects into its analysis. The AESO noted that it had performed regression analysis on TFO projects ranging in capacity from 7.6 MW to 122.8 MW using linear, polynomial, power and exponential curves with results as reported in Table 4 of its argument (reproduced below):

**Table 4. Results of POD Cost Regression Analysis Described in AESO Argument**

Regression Analysis	Line Function	Correlation Coefficient
Linear	$y = 0.0985x + 5.7659$	$R^2 = 0.1289$
Logarithmic	$y = 3.8486\ln(x) - 3.1694$	$R^2 = 0.1939$
Polynomial	$y = -0.0017x^2 + 0.2271x + 3.2723$	$R^2 = 0.1843$
Power	$y = 1.8957 x^{0.431}$	$R^2 = 0.1799$
Exponential	$y = 5.1281 e^{0.113x}$	$R^2 = 0.1249$

Source: Table 4, AESO Argument, p. 76

The AESO noted that the highest regression coefficient was achieved with a logarithmic function, which had a value of 0.1939. The AESO also submitted that the slope of the logarithmic curve would better represent the cost of projects with capacities greater than 50 MW than both the AESO's initial proposed function and cost function proposed by DUC. The AESO also submitted that a multi-part linear function would be consistent with the Board's expectations as indicated in Directive 13A. The AESO also elaborated on its rationale for proposing a 50 MW breakpoint.<sup>166</sup>

PPGA devised a proposal with a fixed charge to reflect a minimum cost associated with a POD and flat per MW charge to reflect the need to recover the residual portion POD charge revenue requirement not recovered through the customer charge.

In anticipation of the possibility that the Board might use the AESO's cost causation data, PPGA also devised an alternate proposal. PPGA noted that it had conducted a series of regression analysis that demonstrated that a breakpoint of 17 MW had the highest level of  $R^2$  for the slope above the breakpoint and for the slopes of both regression lines. PPGA contrasted the 17 MW breakpoint suggested for its alternate proposal with the AESO's proposed 7.5 MW breakpoint which, in PPGA's view, represented no more than a disconnect point between two different data sets and two different equations. PPGA also noted that unlike the AESO's (original) proposal, the y-intercept and slopes for its alternate proposal were derived from its regressions on the dataset.

In argument, while DUC was generally supportive of the AESO's (original) methodology up to 40 MW of billing capacity, it submitted that the AESO's proposal should be adjusted to reflect cost causation and the significant economies of scale present for larger PODs. Accordingly,

<sup>166</sup> AESO Argument, pp. 75-76

DUC proposed a POD cost function identical to the AESO's proposal up to 40 MWs but with an additional tier above 40 MW and a proposed slope of \$30,000/MW.

ADC commented all parties agreed that there are economies of scale in building a POD and that the customer portion of the POD charge should, at minimum, be at the level proposed by the AESO.

ADC submitted that the PPGA's primary proposal assumes that the cost of a substation is linearly proportional to size, which ADC submitted was not supported by any evidence. ADC submitted that a multi-linear function consisting of a series of lines would follow the POD cost function more closely than a simple straight line. Accordingly, if a 17 MW breakpoint was to be used, ADC submitted that the 17 MW breakpoint should only be used in addition to breakpoints at 7.5 MW and 40 MW.

The Board considers that each of the POD cost function proposals devised by the AESO, the PPGA and DUC had, to varying degrees, flaws that prevented the Board from wholly adopting any one party's specific proposal. As is further described below, the Board finds that the POD cost data on record is adequate for the Board to devise an appropriate POD cost function. The Board has relied on a set of 48 data points consisting of the 30 POD greenfield data set contained in the Application,<sup>167</sup> the 13 small pod data contained in the Application<sup>168</sup> and five large pod TCCS data described in the AESO's rebuttal evidence.<sup>169</sup> This dataset was provided as an appendix to the Board's letter to the AESO and all Intervenors dated October 25, 2007.

As discussed in section 5.7.4 above, the Board has accepted that POD costs exhibit significant economies of scale with increasing capacity. As a result, the Board finds that PPGA's primary proposal consisting of only a fixed charge and a \$/MW charge must be rejected because it does not reflect the tendency for POD costs to increase at a decreasing rate with capacity.

Given the existence of significant POD cost economies of scale, the Board considers that the function representing the relationship between POD cost and DTS capacity should have a non-linear shape. However, a reasonable representation of this underlying non-linear function may be represented by a continuous POD cost function from a series of linear functions with different slopes that intersect at specific breakpoints. Accordingly, the Board finds that a compound POD cost function consisting of at least two tiers of linear functions with different slopes (and two breakpoints between the three tiers) would reasonably approximate the underlying POD cost function.

The two tier/17 MW breakpoint POD cost function suggested in the PPGA's alternate proposal was derived by performing separate regressions on subsets of the greenfield data above, occurring both above and below potential breakpoints. However, the Board does not agree that PPGA's alternate proposal is superior based simply on the comparatively higher R<sup>2</sup> values obtained by the PPGA (by performing separate regressions on data above and below the 17 MW breakpoint). Of particular concern to the Board is while that PPGA's alternate proposal uses both the slope and intercept of the regression on POD data with capacities below 17 MWs, only the

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<sup>167</sup> Ex. 016, Application, Appendix G, Spreadsheet tab "Greenfield", cells C3:D32

<sup>168</sup> Ex. 016, Application, Appendix G, Spreadsheet tab "All Projects", cells C38:D50

<sup>169</sup> Ex. 347, AESO Rebuttal Evidence, page 1

slope of the regression (but not the intercept) derived from above 17 MW data is used when PPGA assembles its slopes and breakpoints into a continuous function. Effectively, PPGA's alternate approach ignores the fact that while its below 17 MW regression line has a y-intercept of \$1,579,015, PPGA's above 17 MW regression has an intercept of only \$865,018 – well *below* the intercept of the below 17 MW dataset regression.<sup>170</sup> As a result, the intersection or breakpoint of the two equations occurs at a value of *negative* 3.69 MWs, not *positive* 17 MWs.

The PPGA's proposal to derive a continuous function by assembling the two regressions at the 17 MW breakpoint results in a cost function that is above the greenfield dataset POD cost values for all PODs larger than 17 MWs. As PPGA's alternate POD cost function clearly does not represent an average cost per MW function, the Board considers it to be fundamentally flawed and it is therefore rejected by the Board.

The POD cost functions proposed by the AESO and DUC do not have the same fundamental flaw of PPGA's alternate proposal because they are both primarily based on a single linear function derived through regression analysis on the 30 POD greenfield dataset. These proposed POD cost functions are not without concerns, however.

The first concern is that the AESO and DUC proposals were based on a primary linear cost function with an  $R^2$  value of only 0.26. As further discussed below, the Board has determined that a much better statistical fit may be demonstrated when a different functional form is used.

A second concern relates to the minimum intercept and first tier slope of the AESO's original and revised proposal (and by implication, DUC's proposal). While AESO has indicated that 13 small project data points have been used to devise a cost/capacity relationship for the first tier of the POD cost, both the slope and minimum intercept for the first tier of the AESO's proposed POD cost function relies on only one of the 13 small POD data points.<sup>171</sup> In particular, in Appendix F of the Application, the AESO describes its process for determining the minimum y-intercept of the POD utilizing an "interpolated function" derived by determining the multiplier (0.21275) of the greenfield POD average cost function representing "the threshold below which no project costs were recorded."<sup>172</sup> Accordingly, the Board finds that neither the slope of the first tier nor the AESO's proposed \$0.947 million minimum cost or y-intercept have sufficient validity to be used as the basis for the first tier of the POD cost function.

Board staff used a similar approach to that put forth by the AESO in its argument<sup>173</sup> based on different types of regression analysis performed by Board staff on the 48 point dataset, using linear, logarithmic, polynomial, power, and exponential functions. The results of this analysis are shown below:

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<sup>170</sup> Ex. 328 –Attachment to DUC.PPGA-002(c) (excel file), Tab "Classification 17"

<sup>171</sup> Ex. 015, Application Appendix F, p. 20

<sup>172</sup> Ex. 015, p. 21

<sup>173</sup> AESO Argument, p 76

**Table 5. Results POD Cost Regression Analysis Performed by Board**

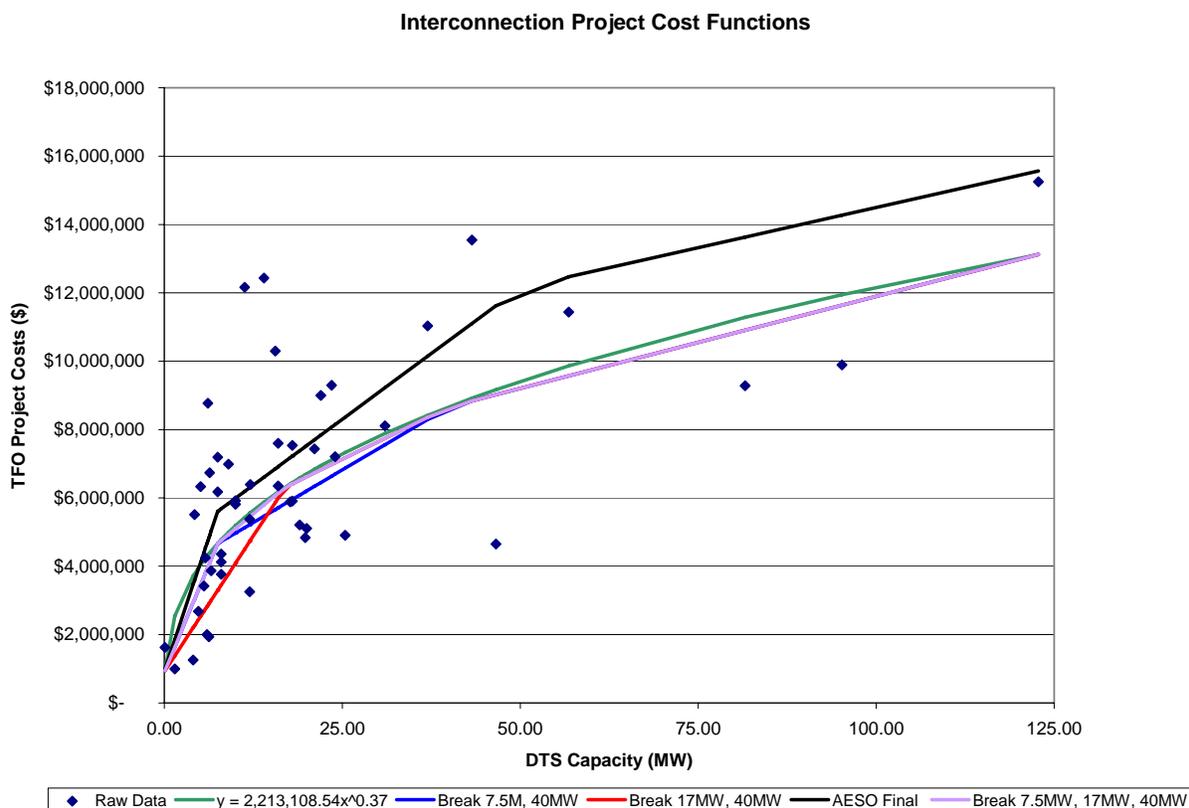
Regression Analysis	Line Function	Correlation Coefficient
Linear	$y = 83,813.50x + 4,807,432.43$	R2 = 0.39
Logarithmic	$y = 1,890,801.87\ln(x) + 1,779,292.09$	R2 = 0.43
Polynomial	$y = -733.27x^2 + 159,898.75x + 3,978,708.36$	R2 = 0.42
Power	$y = 2,213,108.54x^{0.37}$	R2 = 0.49
Exponential	$y = 4,320,826.68e^{0.01x}$	R2 = 0.27

Source: Derived by Board from data in Appendix to October 25, 2007 Board correspondence

The power function provided the best statistical ( $R^2$  of 0.49) and visual fit to the 48 point dataset. Further, this function has the advantage of being continuous in nature, as opposed to the multiple breakpoint linear functions proposed by parties. As a result, unlike the alternate proposal function proposed by the PPGA, the power function does not have the problem of ensuring that the separate linear functions actually converge at the proposed breakpoints.

The Board agrees with the observation of the ADC that a multi-linear function consisting of a series of lines would follow the POD cost function more closely than a simple straight line. Accordingly, Board staff fitted a series of linear functions to replicate the slopes of the power function for various breakpoints. Board staff tested a function with a 7.5 MW and 40 MW breakpoint, another with a 17 MW and 40 MW breakpoint, and finally one with 7.5 MW, 17MW and 40 MW breakpoints.

The cost functions resulting from the linear approximations of the power function, the power function, and the AESO’s final proposed function, are shown below:



Board staff considered that the function with the 7.5MW, 17MW, and 40MW best replicated the power function, and as such this was the POD cost function on which the Board sought submissions from the parties pursuant to its letter dated October 25, 2007. The resulting POD cost function developed by Board staff and on which submissions were sought from the parties was as follows:

$$\begin{aligned}
 Y = & \$0.894 \text{ million} + \$0.503 \text{ million/MW for the first 7.5MW} + \\
 & \$0.174 \text{ million/MW for the next 9.5MW} + \\
 & \$0.102 \text{ million/MW for the next 23MW} + \\
 & \$0.054 \text{ million/MW for all MW above 40.0MW.}
 \end{aligned}$$

During the comment process, a number of parties reiterated their support for their proposed POD cost functions provided earlier in the proceeding. Having reviewed these additional submissions, the Board was not persuaded that its proposed POD cost function was inappropriate.

The submissions received, in response to the October 25, 2007 request for comments on the POD cost function under consideration, generally related to (a) the appropriateness of using the 48 data point POD power function proposed by Board staff as the underlying function; and (b) the proper approach for determining a linear approximation of the underlying POD cost for DTS rate and investment policy purposes.

The AESO raised issues regarding the use of the 48 point dataset suggesting that the 13 small project data points and five large project data points drawn from TFO cost data may be incompatible with the 30 POD greenfield data set.

The Board understands parties' concerns and agrees that the 13 and five data points are not identical to the 30 greenfield data. However, on balance, the Board considers that a continuous cost function is more robust and desirable as it is inclusive of more varied POD data. The Board also agrees with the ADC that a greater error would be created by ignoring the small and large POD data, thereby not representing the effects of economies of scale in the POD cost function. DUC also observed that a POD cost function derived using a power function regression on the 109 POD TCCS data is substantially similar to the power function derived from the 48 POD data set. The Board considers these similarities to be a further indication that use of the 48 POD dataset does not distort the resulting POD cost function.

Although the AESO put forward a non-zero intercept power function,<sup>174</sup> which it submitted had a higher  $R^2$  value than the power function developed by Board staff, it did not suggest that it be used as the basis for a revised cost function. The Board did not fully understand the AESO's rationale for developing a non-zero power function for consideration while not suggesting it be adopted, and sought further clarification by way of an information request on this and other issues raised by the AESO comments.

In response to the Board information request on its comments, the AESO stated that it had improperly calculated the  $R^2$  value associated with its non-zero intercept function. Further, after being in contact with DUC, the AESO decided to adopt a DUC cost function (based on work

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<sup>174</sup> AESO comments on Board Staff Proposed Cost Function, November 5, 2007

DUC had performed in conjunction with the University of Calgary Math Department (UCMD))<sup>175</sup> for the purposes of answering the Board information request.

Based on its work with the UCMD, DUC provided alternative POD cost functions based on variants of the power function.<sup>176</sup> However, the Board is hesitant to apply more than limited weight to these proposals, given the late stage in the proceeding at which this analysis was presented and the limited opportunity of interested parties and the Board to test its validity.

Although the DUC/UCMD alternative proposal II<sup>177</sup> reflected a comparatively high  $R^2$  value (0.48), it was not without pitfalls, which included the linear estimation methodology used by DUC/UCMD and the relatively high POD charge for smaller customers that results from the proposal.

The additional DUC/UCMD analysis followed the AESO's introduction of a possible refinement to the power function developed by Board staff to address the issues raised by the AESO regarding a zero intercept function. The AESO asserted that its proposed non-zero intercept power function exhibited a higher  $R^2$  value than the power function developed by Board staff (*An  $R^2$  of 0.51 versus 0.49*).<sup>178</sup> However, as discussed below, having a zero intercept power function does not invalidate the use of the 48 POD power function developed by Board staff. In any event, the alternative power functions devised by DUC did not produce cost functions that are significantly different visually or mathematically from the zero-intercept power function developed by Board staff.

DUC submitted that the manner in which Excel software calculates  $R^2$  values for power functions may be incorrect.<sup>179</sup> The Board has investigated this issue and has determined that the methods used by Excel and the UCMD to calculate  $R^2$  values may not be the same. However, the  $R^2$  value for the Board staff non-zero intercept power function derived by DUC is not significantly different from the  $R^2$  for this power function as calculated using Excel (a 0.46  $R^2$  as calculated by DUC versus 0.49 for the Excel calculation of Board staff function). The Board further notes that DUC/UCMD calculated the same non-zero intercept power function as calculated by Board staff using Excel.

The method used by DUC to develop linear approximations of the power functions sought to find the best fit for each section of its curve, and then manipulated the resulting linear functions so that they would meet at the desired breakpoints.

This contrasted with the approach adopted by Board staff, which calculated the linear functions by joining the calculated power function value for 0.10MW (the first data point in the 48 point set) to the calculated power function value for 7.5MW by way of straight line. This exercise was repeated for the 7.5MW to 17MW, 17MW to 40MW, and 40MW to 122.8MW (the last datapoint in the 48 point dataset) segments.

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<sup>175</sup> BR.AESO-001(b) of Supplemental AESO IR Responses dated November 19, 2007

<sup>176</sup> DUC Reply Comments dated November 21, 2007, p. 6

<sup>177</sup> DUC submission dated November 21, 2007

<sup>178</sup> AESO comment letter dated November 5, 2007

<sup>179</sup> DUC submission dated November 21, 2007

The Board has reviewed the DUC approach for creating a linear estimate of its power function.<sup>180</sup> The Board considers that Board staff's linear approximation method has the advantage of going through the power function at chosen breakpoints.

With respect to the determination of breakpoints, the Boards considers that a key advantage of creating a linear approximation to an underlying non-linear function, rather than deeming a linear function to be the underlying linear function, is that the POD cost function does not change with changes to the specific breakpoints. For example, if, as recommended by the AESO, a linear function based on the methodology proposed by the AESO in argument, the 30 greenfield dataset is used as the basis of the POD cost function, and an additional tier is added (commencing at a deemed breakpoint of 50 MW), the slope beyond that breakpoint results in a POD cost at 50 MWs. This cost is \$1.024 million higher than the estimated POD cost at 50 MW under the same methodology when a breakpoint at 40MW is selected.<sup>181</sup> As illustrated in Table 6 below, the difference between the POD cost function produced with a 50 MW, rather than a 40 MW breakpoint remains substantial as the size of the POD increases.

**Table 6. Comparison of Impact of 40 MW and 50 MW Breakpoints Under AESO Method**

	50 MW	60 MW	70 MW	80 MW	90 MW	100 MW	110 MW	120 MW
<b>40 MW Breakpoint Cost (\$ millions)</b>	11.126	11.642	12.158	12.674	13.190	13.706	14.222	14.738
<b>50 MW Breakpoint Cost (\$ millions)</b>	12.150	12.620	13.090	13.560	14.030	14.500	14.970	15.440
<b>Diff (\$ millions)</b>	1.024	0.978	0.932	0.886	0.840	0.794	0.748	0.702

Source: Derived by Board from Logarithmic Function described at p. 76 of AESO Argument

The AESO asserted that a 50 MW breakpoint reflects physical changes in the transmission system,<sup>182</sup> for example due to the tendency for multiple transformers to be installed, and should be reflected in the POD cost function. However, the AESO's assertion that the economic or physical configuration of a POD typically changes at 50 MW was not substantiated. It also conflicts with the AESO's evidence in the AESO's 2005-2006 GTA and other evidence in this proceeding. Decision 2005-096 found, on the basis of the AESO's rebuttal evidence filed in that proceeding, the cost of an interconnection using a configuration with two smaller capacity transformers could be more efficient or cost effective than an interconnection devised using a single large capacity transformer.<sup>183</sup> As such, the suggestion that multiple transformers will be used as the size of a POD increases beyond 50 MWs appears to be in conflict with the AESO evidence relied on by the Board in Decision 2005-096. The Board also takes note of the evidence provided by Mr. Chesterman, witness for DUC, that single large transformers have been proposed by the AESO in recent interconnection projects for very large PODs.<sup>184</sup>

<sup>180</sup> DUC submission dated November 21, 2007

<sup>181</sup> AESO argument, pp. 76-77. For levels above 50 MW, the AESO determined a proposed slope of \$47,000 per MW by measuring the rise over run between the POD cost derived from a logarithmic function on a subset of the TCCS measured at 125 MW and 50 MW. Using that methodology and a breakpoint of 40 MW, rather than 50 MW, the slope of the additional tier of the AESO's proposed function increases to approximately \$51,590 per MW above 40 MWs.

<sup>182</sup> AESO Argument, p. 77

<sup>183</sup> Decision 2005-096, p. 53

<sup>184</sup> Tr. Vol. 6, p. 1338

Considering the impact of the choice of specific breakpoints under the AESO's proposed approach and the lack of substantiation of the assertion that 50 MW represents a significant dividing line in the configuration of typical PODs, the Board does not consider that the AESO has provided any persuasive evidence that the 50 MW capacity level has a significance that warrants its selection as a breakpoint under the AESO's proposed approach.

The AESO also suggested that the 7.5 MW capacity level may represent breakpoint where the physical characteristics of a typical POD causes costs to change. The Board understands that the AESO selected the 7.5 MW breakpoint on the basis that it represented the lowest data point available within the greenfield dataset. The assertion that physical characteristics of a POD change at 7.5 MW was not substantiated. The Board agrees with the PPGA that a 7.5 MW breakpoint has not been demonstrated to represent any meaningful physical characteristics, and is arbitrary.

In contrast to the AESO's proposed approach, the method developed by Board staff to create a simplified linear approximation of an underlying non-linear POD cost function does not have the same potential to create significant and arbitrary changes in the POD cost function with changes in specific breakpoints. Under the approach developed by Board staff, the breakpoint for the linear approximation only means that at selected breakpoints, the linear approximation function produces the same POD cost as the underlying non-linear POD cost function. Conversely, due to the shape of the power function, at any other point, the linear approximation falls below the POD cost function. Thus, while the approximation is improved by selecting more breakpoints, the POD cost function developed by Board staff is continuous and does not require breakpoints to be selected to correspond with specifically identified physical characteristics of PODs.

The Board considers that the POD cost functions developed by DUC and by Board staff satisfy the first three Bonbright principles set forth in section 4 of this Decision (recovery of revenue requirement, providing appropriate price signals, and fairness, objectivity and equity). However, the DUC and Board staff POD cost functions can be distinguished on the basis of the secondary criteria of rate stability and predictability. As pointed out in the AESO's reply comments,<sup>185</sup> the cost function recommended by DUC results in a shifting of costs from larger services to smaller customers. The Board observes that the proposed POD cost function developed by Board staff is not likely to result in rates that are substantially different from existing rates, thereby providing greater consistency and stability for smaller customers 1MW-5MW in size.

In light of the above, the Board finds that the linear approximation to the power function based on the POD cost function developed by Board staff, using breakpoints at 7.5 MW, 17 MW, and 40 MWs, produces an acceptable POD cost function for the purposes of the AESO's 2007 tariff.

During the comment and reply process, numerous submissions were made regarding zero intercept and negative intercept functions. However, the highest R<sup>2</sup> proposals (the DUC proposal and the proposal developed by Board staff) have non-zero intercepts after the linear transformations.

Further, even if the underlying power function was to have a zero intercept, it has not been demonstrated that such a power function is fatally flawed.

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<sup>185</sup> AESO reply comments dated November 26, 2007, p.3

First, the Board is not convinced that a zero intercept for a POD cost function is unrealistic or inappropriate. No explanation has been advanced in this proceeding for constructing a POD to provide a DTS capacity at a prudent cost in excess of zero for a demand of zero. In addition, another important characteristic of the power function is a high slope at very low values of x that flattens out quite quickly. As a result, the Board considers that for all but exceptionally low values of DTS contract capacity, the power function based on the POD cost function developed by Board staff provides a cost estimate that is both reasonable and similar to the cost estimates produced by functional forms that include a minimum intercept.

In this regard, 0.1 MW is the lowest DTS value in the 13 TCCS data points provided by the AESO. When a DTS contract capacity of 0.1 MW is evaluated using the POD cost function developed by Board staff, the resulting POD cost is \$944,066.77. This does not significantly differ from the estimated POD cost of \$1,011,100 for a DTS capacity of 0.1 MW that results from the POD cost function proposed by the AESO.<sup>186</sup>

Also notable from the small POD data provided by the AESO is that the lowest POD cost in the 13 POD TCCS dataset (\$994,907) occurs at a DTS capacity of 1.46 MW. From the 13 POD small projects TCCS dataset, this is the sole data point used by the AESO to develop the first tier of its proposed POD cost function. In light of this minimum POD cost of \$994,907, it is notable that the power function based POD cost function developed by Board staff will generate a POD cost at or above \$994,907 for any value of DTS capacity greater than 0.115 MW. Thus, the Board considers that the use of a zero intercept power function is not biased towards estimating very low POD costs for very low capacity PODs since, if anything, the results described above indicate that the POD cost function developed by Board staff is more likely to slightly overstate, rather than understate, POD costs for very low DTS capacity PODs.

In light of the above, the Board considers that any concerns that that the POD cost function developed by Board staff may not properly represent the minimum cost of a POD only arise in relation to extremely small DTS values that have not been shown to generally arise in practice. As such, the Board considers that any theoretical issues related to the properties of the power function at zero and other extremely low values of DTS capacity are of much less concern than the potential for distortions to be caused by using a functional forms that do not reflect the evidence accepted by the Board in section 5.7.4 that economies of scale generally cause POD costs to rise at a decreasing rate with increases in contract capacity.

For these reasons, the Board finds that the POD cost function developed by Board staff that was released for comment on October 25, 2007 is the function to be used by the AESO.

The Board directs the AESO to reflect the Board approved linear POD cost function in the AESO refiling as noted below:

$$Y = \$0.894 \text{ million} + \$0.503 \text{ million/MW for the first 7.5MW} + \\ \$0.174 \text{ million/MW for the next 9.5MW} + \\ \$0.102 \text{ million/MW for the next 23MW} + \\ \$0.054 \text{ million/MW for all MW above 40.0MW.}$$

<sup>186</sup> \$1,011,100 = 947,000 + (.1) x 621,000. Figures obtained from AESO argument, page 78

The Board will address the function multiplier to be applied to this cost function to develop the Board approved investment formula in section 8.1.2.2 of this Decision.

### 5.7.8 Other POD Charge Related Issues

Certain parties raised other issues relating to the POD charge. These issues included additional cost causation design credits, the treatment of radial versus looped line costs in the POD cost function, and the treatment of TFO O&M costs in the POD cost function. These issues are addressed below.

#### 5.7.8.1 Additional Cost Causation Design Credits

PPGA submitted that regardless of the POD established by the Board (including PPGAs proposed POD charge of \$4725/month plus \$1447/MW/month), the POD charge should be further adjusted to apply credits to small customers to reflect the AESO's policy of standardizing facilities to a minimum of 138 kV. In addition, PPGA, recommended adjustments reflecting the AESO's classification of transformer high-side breaker costs as local costs (rather than POD costs).<sup>187</sup>

As illustrated in a table provided in its evidence,<sup>188</sup> PPGA submitted that a 69kV interconnection is approximately 9% less expensive than a similarly sized 138 kV interconnection, primarily as a result of the lower cost of a 69kV transformer. Accordingly, PPGA submitted that a 9% credit or reduction should be applied to the fixed monthly charge portion of the POD charge adopted by the Board. To retain revenue neutrality, PPGA proposed that this credit should be funded by a higher POD charge to loads greater than 20 MW.

With respect to breaker costs on the high voltage side of the transformer, PPGA submitted that high-side breaker costs represent 2% of the cost of an average POD connection. Accordingly, PPGA submitted that 2% of POD costs should be moved from POD costs to the local system cost category. To the extent the Board were to accept PPGA's proposal to account for high-side breaker costs, PPGA submitted that the POD cost revenue requirement should be reduced by \$3.6 million.<sup>189</sup>

CCA/PICA submitted that the economics of a PPGA member's choice to connect at the Disco rather than through a direct transmission connection is part of the risk assumed by the customer. Accordingly, CCA/PICA submitted that it would not be appropriate to provide a credit for smaller PODs connecting to the transmission system. CCA/PICA suggested that the PPGA recommendation to move high side breaker costs from the POD cost to the local cost category would be appropriate to the extent that the high side breaker equipment forms part of the network or looped system, which is part of the local system.

As discussed in section 2 above, recognizing different operational circumstances and their cost implications does not, in itself, contravene subsection 30(3) of the EUA. However, the Board is

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<sup>187</sup> Ex. 239, PPGA Evidence, p. 18

<sup>188</sup> Ex. 239, PPGA Evidence, p. 18

<sup>189</sup> Ex. 239, PPGA Evidence, p. 19

not persuaded that PPGA's proposed credit to small customers, to reflect the differential in costs between 69kV and 138 kV interconnection facilities is warranted.

Within the context of a postage stamp rate design, a certain amount of averaging is present. The Board considers that the DTS rate should show a high degree of uniformity across AESO customers and therefore, proposed differentiations from the uniform rate should be subject to significant scrutiny by the Board before any such proposal is granted. The Board also agrees with CCA/PICA that the economic impact of a choice to connect to the transmission system rather than to a Disco is a risk assumed by the customer.

The Board agrees with the AESO that the nature of the service provided to AESO customers that sign up for system access service is not determined by the voltage level of the interconnection facilities.

PPGA's proposal to classify breakers on the high voltage side of a transformer as local system costs (rather than POD costs) relates to functionalization as between local and POD costs, rather than to the design of the POD charge itself. The Board agrees with the AESO that no adjustment to the functionalization of local and POD costs is necessary to account for high-side breaker costs. As discussed in the TCCU,<sup>190</sup> the functionalization of TFO cost to POD costs includes the cost of radial lines. Given that radial transmission lines will include facilities located on the high-voltage side of the transformer, it follows that breakers that happen to be located on the high-voltage side of the transformer would be functionalized as POD costs.

Given the foregoing, the Board does not accept the PPGAs proposal to reduce POD costs by \$3.6 million to reflect the functionalization of high-side breaker costs from POD to local.

#### **5.7.8.2 Treatment of Radial vs. Looped Line Costs in POD Cost Function**

CCA/PICA expressed concern that by including full radial line costs in its POD cost function, the AESO has overstated the level of the first block of variable demand component of its proposed POD cost function. In particular, CCA/PICA submitted that because only 34% of PODs are radially fed while the remainder of the PODs are looped, radial line costs are not applicable for 66% of substations.<sup>191</sup> To address its concern that the AESO's proposed POD cost function may reflect the cost of looped transmission lines, CCA/PICA proposed adjustments to POD cost functions used for both the POD charge and the maximum investment function.<sup>192</sup>

CCA/PICA argued that for the purposes of developing its cost functions, the AESO considered substation and radial line costs together in its regression analysis of 30 greenfield projects. In contrast, CCA/PICA submitted that its evidence considered the average cost of lines separately from the substation function when developing the POD cost function and investment function. CCA/PICA further submitted that as there is no relationship between the length of a radial line and the size of a POD, it would be appropriate to consider radial line costs and substation costs separately, both for POD cost and investment function purposes.

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<sup>190</sup> Ex. 012, TCCU, page 47

<sup>191</sup> Ex. 225, CCA/PICA Evidence, p. 8 citing Application Appendix C (Ex. 012), p. 43

<sup>192</sup> Ex. 225, CCA/PICA Evidence, pp. 8-10

Submissions on various considerations relating to radial as compared to looped lines within the POD cost function were also received from the AESO and DUC. These submissions, and the reply argument of CCA/PICA primarily addressed:

- the need to consider the tendency of radial lines interconnections to become looped over time;
- the impact of radial lines on the proportion of POD costs that should be considered fixed rather than variable with POD capacity;
- whether a double count occurs as a result of the inclusion of the costs of looped lines in the POD cost function;
- whether the proposals of CCA/PICA adequately reflected the impact of economies of scale on POD costs

The adjustment proposed by CCA/PICA to the POD cost function for the POD charge was to reflect both the tendency of radial lines to become looped over time and the findings of PS Technologies that only 34% of lines are connected to radial lines.

However, the Board considers the observation that 34% of PODs are connected to radial lines to be primarily, if not exclusively, a TFO cost functionalization issue. It is not a concern in respect of the allocation of functionalized POD costs for determining the POD charge.

Given that in the context of the POD charge, the POD cost function is used to allocate POD related costs among DTS customers of various sizes, the Board does not consider it to be necessary or appropriate to modify the POD cost function or the POD charge unless it can be demonstrated that there is a greater tendency for smaller or larger PODs to be connected radially rather than to the looped system. However, the reply submission of CCA/PICA acknowledges that radial lines costs are essentially fixed and unrelated to the size of the POD. CCA/PICA clarified in their reply that the lower allocation of radial line costs to smaller customers had been proposed primarily to provide rate relief to such customers. The Board has previously found that stability and predictability of rates is afforded secondary consideration. This is a separate issue from the POD cost function for the purposes of the POD charge. Any rate shock that arises from the Board's findings, including changes to the POD charges, is addressed in section 5.9 of the Decision.

Given the foregoing, the adjustment to the POD charge cost function proposed by CCA/PICA is denied.

### **5.7.8.3 Treatment of TFO O&M Costs in POD Cost Function**

PPGA submitted in its evidence that the AESO had provided no evidence, facts or analysis to support its assertion that O&M costs follow capital costs. Given this, PPGA submitted that the AESO's proposed POD charge does not reflect true cost causation. PPGA questioned the validity of the AESO's entire POD charge rate proposal.

PPGA argued that even though TFO O&M costs are in the range of \$130-\$150 million, the AESO had simply asserted that the impact of O&M costs on the POD cost function would be small.

The AESO argued that the classification and functionalization of transmission wires costs resulting from the TCCU was generally accepted by participants in this proceeding, other than PPGA. The AESO noted that Decision 2005-096 had set out two directions respecting cost classification, including a direction that the AESO analyze the functionalization and classification of O&M costs.<sup>193</sup>

The AESO noted that that PS Technologies' analysis of O&M costs found that data was not available to allow refinement of the functionalization and classification of OMA costs to reflect the impact of equipment vintage and type. In any event, the TCCU expected the impact on total cost functionalization and classification to be small because O&M costs account for about one-quarter to one-third of TFO revenue requirements. The AESO further noted that PS Technologies had not recommended any changes to transmission cost functionalization or classification as a result of its review of O&M costs for the TCCU.

Although the PPGA took issue with the AESO for not having conducted research in support of its assertion that TFO O&M costs vary with POD capital costs, the PPGA provided no evidence indicating that TFO O&M costs do not vary with the level of POD capital costs. The PPGA also did not provide evidence of whether the AESO's proposed POD cost function would understate or overstate the causation of TFO O&M costs.

In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs.

## **5.8 DTS Rate Summary**

As noted in the introduction to this section the AESO has proposed a number of significant changes to the structure of the DTS rate. The Board considers that it may be helpful to readers to provide a summary of its findings and directions with respect to the DTS Rate.

In support of its Application, the AESO supplied the 2006 TCCU, an update to the TCCS of 2005. The TCCU updated the functionalization of transmission assets provided in the TCCS, and subsequently approved by the Board in Decision 2005-096. The functionalization provided in the TCCU regarding bulk wires costs, local wires costs and POD costs showed little, if any, change from the TCCS and it has been approved by the Board in this Decision.

With respect to classification of bulk and local wires costs, the bulk of the TCCU was devoted to advancing the hypothesis that load in all hours is more important to cost causation than peak loads that occur over a few hours during the course of the year. The AESO further supported this hypothesis in Appendix D to the Application. Given this evidence, the AESO proposed to bundle both bulk and local wires costs, to classify approximately half of these costs as energy related through the use of the A&E methodology and to collect these costs through an all hours energy

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<sup>193</sup> Decision 2005-096, p. 23

charge. The balance of bulk and local wires costs was to be classified as demand related and collect through a non-coincident peak (NCP) demand charge, using the same ratchet provisions as contained in the current tariff.

The Board has rejected this hypothesis. The Board has determined that only 18% of wires costs, as demonstrated in the TCCU, are to be classified as energy. The Board also found that bulk and local wires costs are to continue to be unbundled so that the balance of these costs could be collected through two different demand charges. The Board determined that the demand related portion of bulk wires costs is to be collected through a twelve coincident peak (12 CP) demand charge as this would send the most appropriate price signal to customers and was consistent with cost causation and how the system was planned. The demand related portion of local wires costs is to be collected through a non-coincident peak demand charge utilizing the ratchet contained in the current tariff.

With respect to the classification of POD costs, the AESO has proposed to classify 88% of POD costs as demand related, a significant change from the results of the original TCCS, in which 56% of POD costs were classified as customer related. The AESO justified this change on the basis of its examination of costs contained in the contribution policy study. The Board has approved the classification approach proposed by the AESO.

With regard to the structure of the POD charge, the AESO originally proposed in the Application a rate composed of a customer charge and a two tiered demand related charge. In argument, the AESO amended its proposal to include a third tier in the demand charge, similar to that proposed by DUC. After performing its own calculations, the Board has determined that a four tier demand charge would more accurately and fairly recover POD costs while not adding undue complexity or administrative burden.

Additionally, the Board has now dealt with significant rate design issues involving the DTS rate in two consecutive GTAs. Absent significant and unanticipated events, the Board does not consider that significant adjustments should be necessary in the foreseeable future. In particular the Board considers that the portion of wires costs classified as energy related should remain fairly low and be determined by the cost of service study, not by the use of such questionable methodologies as the A&E method. The Board has found that transmission wires costs are largely fixed in nature and are most appropriately recovered primarily through demand charges.

Certain parties suggested that the AESO should be directed to conduct more research into the Operations, Maintenance and Administrative costs (OM&A) of the TFOs with a view to determining a more precise classification of wires costs. The Board has dealt with this proposal elsewhere in this Decision, directing the AESO to provide its views on the feasibility of such further study.

The Board's findings and directions can be summarized as follows:

- The functionalization of transmission costs as illustrated in section 4.3.5 of the Application is approved as filed.
- Bulk and local wires costs are to be classified as 82% demand related and 18% energy related.

- The rate design shall collect the 18% energy related costs of bulk and local wires costs on the basis of an all hours energy charge.
- The demand portion of bulk wires costs shall be collected on the basis of a 12 CP demand charge.
- The demand portion of local wires costs shall be collected on the basis of an NCP demand charge as determined by billing capacity and utilizing the same ratchet provisions as the current tariff.
- The classification of POD costs proposed by the AESO in section 4.3.4 of the Application and as refined by the Board is approved.
- The rate design of the POD charge shall collect the customer related portion of costs based on a uniform monthly charge to each POD. The demand related portion of costs shall be collected using the four tier approach as described by the Board in section 5.7.7 of this Decision, with the billing determinant for each POD being based on NCP as determined by billing capacity and utilizing the same ratchet provisions as the current tariff.

The AESO is directed to reflect the above in its refiling. Based upon the information the AESO has been directed to provide in the refiling, the Board will determine what, if any, rate mitigation measures are necessary.

## 5.9 Rate Shock

The AESO argued that its proposed rate design provided an appropriate moderation of bill impacts. However, the AESO acknowledged that its analysis of bill impacts established that some PODs may experience “unreasonably” high increases, based on a comparison its 2007 proposed rates to its 2005 approved rates. The AESO suggested that any individual POD that experiences both an increase of more than 300% due to the change from the 2005 to 2007 DTS rate and also an increase due to the change from the 2006 to 2007 DTS rate, should be eligible for bill impact mitigation.

In argument, the AESO submitted that if a POD will not experience an increase from the 2006 to 2007 rate change, it should not be subject to bill impact mitigation, regardless of the increase it may have experienced from the rate change that occurred from 2005 to 2006, since such customers would have already accommodated previous increases.

The AESO explained that the 300% cap was based on a maximum increase of 100% over a single rate change, applied over two consecutive rate changes (2005-2006 and 2006-2007) and the AESO’s view that the cap should apply to as few customers as possible to minimize subsidization between customers.<sup>194</sup> The AESO proposed that the cap apply only until December 31, 2008, and submitted that it therefore would need to be high enough that the bill impact on expiry of the cap is reasonable.

As a result, the AESO submitted that:

Based on these considerations and the analysis of POD-specific bill impact provided in BR.AESO-003 (a)-A Rev 2 (Exhibit 214), only eight PODs will require bill impact mitigation. The AESO proposes to implement the bill impact mitigation through Bill

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<sup>194</sup> This was also as discussed in Ex. 094, ADC.AESO-021

Impact Mitigation Rider G, for which a preliminary rider schedule was included as part of the proposed tariff in Section 7 of the AESO's Application (Exhibit 008).<sup>195</sup>

The PPGA argued that any rate shock analysis should compare 2005 rates to the AESO's proposed 2007 rates.<sup>196</sup>

The ADC urged the Board to consider only the 2006 rates when applying the intent of moderation.<sup>197</sup>

DUC submitted that the appropriate test of rate shock should be a comparison of 2006 to 2007 tariffs, and that based on this comparison, no rate shock would be created by the proposed changes from the 2006 approved and 2007 proposed tariffs.<sup>198</sup>

TCE submitted that if the Board retained the 12 CP allocation methodology for the bulk system, the amount of rate shock mitigation measures would be minimal, if any.<sup>199</sup>

In Decision 2005-096 the Board ruled, in the context of that AESO decision, that rate shock be given secondary consideration as a rate design criteria, and that on balance, if rates reflect causation, barring unusual regulatory events such as regulatory lag or a dramatic change in cost structure, there should be little need to be concerned about the principles of rate shock and gradualism.

The Board considers that no reasons for deviating from cost-based rates exist in the context of this proceeding. The Board directed cost allocation methodology approved in section 5 of this Decision is similar to that contained in the current AESO tariff, and as such, no dramatic change in cost structure is present.

With respect to the issue of an appropriate rate comparison benchmark, the Board agrees with ADC and DUC that the appropriate comparator for the 2007 tariff is the 2006 Board approved tariff. This is consistent with past Board Decisions where the impact of a proposed tariff is evaluated against the previous approved tariff.<sup>200</sup>

The Board has, in section 5.0 of this Decision, directed the AESO to modify its proposed cost allocation and rate design. Based on the expert evidence<sup>201</sup> put forth in this proceeding, the Board does not consider that these changes are likely to result in rate impacts to a significant number of the individual PODs served by the AESO when compared to the existing 2006 rates, however the Board recognizes that the potential exists.

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<sup>195</sup> AESO Argument, pp. 46-47

<sup>196</sup> PPGA Argument, pp. 15-16

<sup>197</sup> ADC Argument, p. 5

<sup>198</sup> DUC Argument, p. 21

<sup>199</sup> TCE Argument, p. 41

<sup>200</sup> For example, in Decision 2005-096, the Board used the AESO's previous tariff for comparison. Such practice is also followed in evaluating Distribution Company's proposed Tariffs as well, for example, see Decisions 2007-022, 2004-066, 2004-067.

<sup>201</sup> Ex. 159, BR.AESO-003 and ADC Evidence of Dr. Rosenberg (Ex. 221)

Therefore, the Board directs the AESO to prepare bill impacts that compare the bills which result from the directions in this Decision to the current Board approved tariff. The bill comparison will include all components of a customer's bill, including commodity costs, similar in format to Board information request BR-AESO-003.<sup>202</sup> The pool price assumed for the commodity charge is to be the same for both periods so that the comparison isolates the increase attributable to transmission costs only. All other assumptions used in developing the results and the impact of those assumptions are to be included in the analysis. For any POD receiving an increase of greater than 10% (in comparison to the 2006 tariff), the Board directs the AESO to provide the nature of the customers served by each POD (whether Disco, direct connect, or a Disco customer on a flow through rate), the total dollar impact to the POD and the total amount it would cost to subsidize all such PODs down to the 10% increase level.

## 5.10 Primary Service Credit

### 5.10.1 PSC Methodology

In Decision 2005-096 the Board explained the rationale for the Primary Service Credit (PSC) as follows:

The Board understands the rationale for the payment of the credit is that the credit reflects the fact that DTS customers have paid for the full cost of transformation facilities at their site. As DTS customers, they have signed a contract with the AESO for service and are obligated to pay fixed DTS charges related to their contract capacity. Included in this fixed charge is payment to the AESO for the cost of transformation equipment that the system would usually pay for and provide to the customer. As the customer has already paid for the full cost of transformation equipment at their site, it is not necessary for the system to invest in such facilities.

Consequently, if no credit were available to these customers they would be in a position of paying twice for one set of transformation assets – once when the customer installed and paid for the assets, and a second time when paying their fixed DTS charges each month. The Board does not consider it reasonable to compel a customer to pay twice for one set of assets. It follows that a credit should be available to such customers to ensure that they do not pay twice. The Board considers this to be just and reasonable.<sup>203</sup>

The DTS rate, and the POD charge component of it, are postage stamp in nature. As such, the purpose of the PSC is not to refund to a specific customer exactly what it has paid for a particular asset but rather to provide a credit representing a portion of the DTS charge that represents payment to the AESO for the cost of transformation equipment that the system would usually pay for, but that customers have already paid for themselves.

In the Application, the AESO has proposed to change the structure of the PSC, from the \$/MW basis approved in Decision 2005-096,<sup>204</sup> to align it with the POD charge component of the DTS rate. It proposed that the level of the PSC be established at 40% of the level of the POD charge. The AESO considered that the structure of the PSC should follow the structure of the POD charge, such that the credit incorporates 40% of each component of the proposed POD charge, as follows:

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<sup>202</sup> Ex. 064

<sup>203</sup> Decision 2005-096, p. 38

<sup>204</sup> Decision 2005-096, p. 40.

Primary Service Credit:  
 \$1,252.00/MW multiplied by the Substation Fraction for the first 7.5 MW of Billing Capacity, plus  
 \$310.00/MW for all Billing Capacity over 7.5 MW, plus  
 \$1,905.00/month multiplied by the Substation Fraction<sup>205</sup>

The PSC evolution follows that of the POD charge, as it is a portion of the POD costs that are refunded by the PSC. Parties made various proposals for the PSC that they wished to be approved by the Board.

The AESO originally proposed a two tier POD charge (up to 7.5 MW and over 7.5 MW) and proposed a PSC rate of 40%.<sup>206</sup>

DUC proposed a rate of 55% for the first two tiers (up to 7.5 MW, 7.5 MW to 40 MW) and 100% for the third tier (incremental loads above 40 MW).<sup>207</sup> DUC's recommendation for a PSC rate of 55% of the POD charges was based upon the fact that customers supplied their own substations, not just transformation equipment, as shown in Figure 19 of DUC's evidence. DUC also recommended that the PSC for incremental billing capacity over 40 MW be set equal to their recommended POD charge for billing capacities in excess of 40 MW, a 100% PSC rate for billing capacity in excess of 40 MW. DUC supported this recommendation based upon its evidence which showed that the only incremental cost incurred above this level was for transformation equipment.<sup>208</sup>

In argument, the AESO observed that DUC's methodology relied directly on the new project data in the Application, which the AESO's proposed PSC level did not. As such, the AESO considered DUC's approach to be superior and should be adopted.<sup>209</sup> The AESO then proposed a three tier POD charge (up to 7.5 MW, 7.5 MW to 50 MW, over 50 MW) and proposed a PSC rate of 55%.

TCE argued that those customers who had supplied their own substation should receive a 100% PSC.<sup>210</sup> TCE maintained that the usage patterns of such customers is not the same as regular customers since these customers receive power further upstream than regular customers and the service is different. TCE argued that customers who own their own substation are responsible for all of their own maintenance, including replacement of major equipment such as transformers and breakers. TCE maintained non-substation costs could be directly assigned to a particular customer and their POD charge set to zero.<sup>211</sup>

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<sup>205</sup> Ex. 005, Application, Section 4, p. 51

<sup>206</sup> Ex. 005, Application, Section 4, p. 51

<sup>207</sup> Ex. 229, DUC Evidence, pp. 34- 36 and Figure 19

<sup>208</sup> Ex. 229, DUC Evidence, pp. 14-17

<sup>209</sup> AESO Argument, p. 62

<sup>210</sup> TCE Argument, p. 61-62

<sup>211</sup> See TCE.AESO-059 (Ex. 126) and TCE Argument, pp. 58-61

In reply DUC noted that for the final tier, the AESO was of the view that the PSC should be 55% of the POD charge, whereas DUC was of the view that it should be 100% of the POD charge. DUC noted the AESO summarized its concerns in argument.<sup>212</sup>

DUC disagreed and argued that the PSC should reflect cost causation. In order that the PSC does so, it is necessary that there be no incremental POD costs above 40 MW (or 50 MW as per the AESO) for customers that own their own substation.<sup>213</sup>

DUC disagreed with the AESO's suggestion that there may be some radial lines costs that are higher for larger PODs<sup>214</sup> and that "[i]n the absence of detailed project data to the contrary ...radial line costs likely increase for larger PODs in a manner comparable to the increased costs of transformation." DUC argued that the AESO's own evidence strongly suggests that there is no correlation between POD size and radial transmission line costs.<sup>215</sup>

The AESO disagreed with DUC's proposal for a 100% credit at the third tier (over 40 MW) level. The AESO submitted that DUC's proposal was based on the hypothesis that above a certain size, the only incremental cost attributable to increasing size relates to the size of transformation. The AESO suggested that radial line costs are likely to also contribute to increasing POD costs for larger PODs for two reasons. First, larger PODs more frequently, and sometimes exclusively, interconnect at 240 kV voltage (rather than 138 kV or 69 kV) and these higher voltage lines are more expensive. Second, larger PODs are generally associated with larger projects for which the incremental cost of locating farther from the existing transmission system may be a lesser consideration than for smaller projects. For example, the AESO stated the large developments occurring in the Fort McMurray area require significant line extensions which would generally not be justifiable for a customer with a smaller project. In the absence of detailed project data to the contrary, the AESO submitted that radial line costs likely increase for larger PODs in a manner comparable to the increased costs of transformation. It was therefore appropriate to maintain the 55% credit against the final component of the POD charge, rather than increase the credit to 100% as proposed by DUC.

In section 5.7.7 of this Decision, the Board has directed the AESO to implement a POD charge design which incorporates four tiers, with the fourth tier commencing at 40 MW.

Both the AESO and DUC have agreed that the PSC for the first two tiers (the first three tiers or up to the 40 MW level under the Board approved approach) should be 55%. ASBG/PGA has argued that it should only be 40%, as originally proposed by AESO. The Board disagrees with ASBG/PGA. The Board considers the evidence of DUC, in particular Figure 19 of its evidence, and endorsed by AESO, to be persuasive. As the AESO explained, DUC's methodology relied directly on the new project data in the Application, which the AESO's proposed PSC level did not. As such, the AESO was of the view that the DUC approach is preferable, and should be adopted. This evidence concluded that 55% was the appropriate PSC level for capacities up to the 40 MW level.

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<sup>212</sup> AESO Argument, p. 62, l. 39 – p. 40, l. 2

<sup>213</sup> DUC Reply, p. 9

<sup>214</sup> AESO Argument, p. 36, l. 29-39

<sup>215</sup> Ex. 126, TCE.AESO-025

The Board does not accept TCE's argument that customers who provide their entire substation should receive a 100% credit. The POD charge is a postage stamp rate component designed to recover, on an average basis, all costs related to PODs. This includes costs not related to substations, such as radial line costs. The Board considers that a 100% PSC for those levels below 40 MW would not recover an appropriate share of non-substation related costs from these customers.

For these reasons the Board approves a PSC rate of 55% for the first three tiers (capacity levels up to 40 MW) of its approved POD charge design.

With respect to the PSC rate for the fourth and final tier (for incremental capacity above 40 MW), the Board agrees with DUC and approves a PSC rate of 100%. In the rate design directed for the POD charge and the investment function, the rate for the fourth tier has been set at a sufficiently low level that generally the investment that will be made and generally the cost recovered is that related to the incremental cost of transformation.<sup>216</sup> The Board considers that costs related to non-transformation assets will be recovered in the charges related to the first three tiers or through a customer contribution when system access is originally provided to a customer.

In summary, the Board considers that these PSC rates appropriately credit to customers the amount of the POD charge that is related to facilities they have provided while at the same time ensuring they make a contribution to the cost of non-transformation assets provided for customers. The AESO is directed, in its refiling application, to make the necessary adjustments to the PSC rate to reflect the rates approved by the Board in this Decision.

### 5.10.2 PSC Eligibility

In the Application, the AESO also proposed to change the focus of the PSC eligibility criteria so that instead of focusing on whether the customer owned transformation would have reduced TFO investment, it would focus on whether the TFO owns conventional transformation equipment used in providing service to the customer. The AESO considered that this change would appropriately accommodate the unconventional and "virtual" interconnections. The AESO also considered that its proposed change would simplify the eligibility criteria.<sup>217</sup>

Regarding unconventional interconnections, the AESO stated that some small loads are interconnected to the transmission system through facilities such as metering transformers, rather than load transformers. Such small loads would generally be served through a distribution connection, but at the time of interconnection were probably located more closely to a transmission line than a distribution line. Distance-related considerations likely led to choosing a transmission interconnection, while using metering transformers instead of a conventional substation resulted in substantially lower costs to do so. Given this lower total cost, the unconventional interconnection would connect to the transmission system rather than a distribution network.

Regarding "virtual" interconnections, the AESO considered some small loads to be receiving "virtual" transmission services. Under section 3(b) of the *Isolated Generating Units and*

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<sup>216</sup> See Section 5.7.4, refers to CG.DUC-1(c) and DUC Evidence (Ex. 229), pp. 13-16

<sup>217</sup> Ex. 005, Application, Section 4, p. 52

*Customer Choice Regulation*,<sup>218</sup> transmission charges are attributed to an isolated community “as if the isolated community were being provided with system access service via the interconnected electric system.” However, there is no physical transmission substation associated with the isolated community. If those communities were actually connected to the electric system, their small capacities would likely lead to connection through a distribution network, rather than directly to the transmission system as a stand-alone substation.<sup>219</sup>

DUC disagreed with the AESO that isolated generating units should be eligible for the PSC. DUC noted in its evidence<sup>220</sup> that the tariff from ATCO Electric to the AESO includes the revenue requirement associated with the isolated generation units, including capital recovery, maintenance and fuel costs. In DUC’s experience the provision of electricity from remote generators has a full cost in excess of \$250/MWh.<sup>221</sup>

DUC also noted that while the tariff from ATCO Electric to the AESO for the isolated generation units excludes costs related to transmission substations (as there are none), the isolated generation unit costs are included. DUC observed that costs per isolated generation site are on average over \$2 million per year,<sup>222</sup> well in excess of the estimated DTS revenue of the \$160,000 per year the AESO receives from each of these sites.<sup>223</sup>

DUC opposed extending the PSC to isolated generation communities. It maintained that dual use customers experience increased costs and cause decreased costs to all other AESO customers by investing in their own facilities. It considered that in the case of the isolated generation units, there is no cost saving choice. The lowest cost option (interconnection to the grid or isolation generation unit) is provided. There is no avoided investment that makes AESO customers better off, and hence there should be no tariff cost reduction (through a PSC to AE) for the isolated generation units. DUC did consider it appropriate to provide the PSC to the two unconventional interconnection sites, since the use of less costly devices such as a potential transformer, instead of a transformer, generally result in a significant capital cost reduction and savings to other AESO customers.<sup>224</sup>

CCA/PICA supported the AESO in extending the PSC to isolated community PODs, since those PODS do not own conventional transformation facilities. They argued that an economic choice was made to use isolated generation instead of conventional transformation with interconnection to the grid. This choice was considered to be no different than an industrial customer who makes an economic choice between providing its own transformation or using system supplied transformation. If the industrial customer is eligible for primary service credit so should the isolated community, argued CCA/PICA.

In reply DUC stated that CCA/PICA failed to recognize the significant difference between the choice ATCO Electric made to serve remote communities with diesel fired generation and the

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<sup>218</sup> Alberta Regulation 165/2003, as amended

<sup>219</sup> Ex. 005, Application, Section 4, p. 52 and p. 20

<sup>220</sup> Ex. 229, DUC Evidence, p. 38

<sup>221</sup> Ex. 229, DUC Evidence, p. 38, citing ATCO Electric’s 2007 TFO filing forecast cost of \$247/MWh excluding return on equity and debt costs (p. 4-1 & Schedules 5-1, 5-6 & 6-6)

<sup>222</sup> ATCO Electric’s 2007 TFO Filing shows forecast cost of over \$18 million excluding return on equity and debt costs and Schedule CG.AESO-17 (b), p. 2 of 2, shows a total of eight isolated sites.

<sup>223</sup> DUC POD PSC Evidence CG 17 Expanded.xls, tab CG-017 (b-c) PSC Details p2, cells M8:R22

<sup>224</sup> Tr. Vol. 6, p. 1367

choice that industrial customer made to own the substation. All of ATCO Electric's costs to provide service to the remote communities are included in either ATCO Electric's tariff or in the AESO's tariff. None of the costs an industrial customer invests in its substation are reflected in the AESO's tariff or any other tariff. Since there is no capital investment reductions, and resulting cost benefit to AESO customers, from the isolated generation PODs, DUC maintained the PSC should not apply to them.

TCE maintained that isolated generation customers are already receiving what appears to be a substantial subsidy from other transmission customers,<sup>225</sup> and that it was therefore inappropriate to provide them with a credit for a transmission facility that they do not require, but for which they have made no expenditure.

In argument, the AESO proposed that that the PSC should apply to all PODs which, for whatever reason, do not make use of transformation.<sup>226</sup> It considered that this would allow the POD charges to appropriately reflect average costs where customers have installed their own transformation facilities, for PODs that are small and/or unconventional, and for isolated communities.

The Board accepts the evidence of DUC that isolated generation unit customers are already receiving a considerable cross-subsidy from other customers. The Board also agrees with TCE that it would be inappropriate for customers already receiving the benefits of isolated generation service to receive additional benefit through the PSC. The Board rejects the argument of CCA/PICA that the isolated generating units should be eligible because the AESO has not invested in standard facilities. The Board considers that the PSC should only be paid when a customer both avoids AESO investment and genuinely reduces costs to other customers. In the case of the isolated generating units, the customers have not provided their own facilities and no real savings to other AESO customers have been demonstrated. Isolated generation is a substitute for transmission service. The savings related to an isolated generation connection are already captured by the fact that the load is being served by isolated generation, thereby alleviating the need to pay for a transmission line to be built and maintained, and further alleviating the risk of stranded costs. The Board therefore finds that the isolated generating units are not to be eligible for the PSC.

The Board does concur with the AESO's proposal to extend the PSC to other unconventional interconnections, as described in section 4.5.2 of the Application. As noted by DUC these interconnections have resulted in reduced costs to other customers.

The AESO is directed in its refiling application to amend the PSC rate schedule to reflect the Board's findings that eligibility for the PSC is to be restricted to dual use customers and those unconventional interconnections described by the AESO in section 4.5.2 of the Application. Isolated generating units will not be eligible.

## 5.11 Standby Rates

During the AESO's 2005/2006 GTA, the AESO committed to consider the need for a backup or standby service in its next tariff application. It defined standby service as serving a customer load

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<sup>225</sup> Ex. 229, p. 38, lines 21 to 25

<sup>226</sup> Ex. 005, p. 52

that would otherwise be fully served by onsite generation during unscheduled outages of the onsite generation.<sup>227</sup>

The AESO noted that service of this nature is usually required for periods of short duration, no more than a few times per year and cannot be predicted with certainty as the backup service is generally required to allow a load process to continue uninterrupted when on-site generation suffers an unexpected outage. The AESO noted that while the AESO tariff does not presently contain a specific provision for backup service, such use of the transmission system is not prevented in any manner, except by capacity or other system constraints. The AESO indicated that its stakeholders have questioned whether the charges incurred reasonably reflect the costs caused by such use of the transmission system, when backup service is taken under the DTS rate.<sup>228</sup>

The AESO noted that stakeholders are generally concerned about the demand charge components of the bulk system and local system charges under the current DTS rate. The AESO indicated that those components include a two year 90% ratchet provision which results in long-term impacts when backup service is used for short periods of time.

Having studied the attribution of transmission system costs to backup service, the AESO concluded that a separate backup rate was not needed. It therefore did not propose a backup rate in the Application. The AESO considered, and CCA/PICA agreed, that its proposed DTS rate accommodates the cost and rate design considerations related to the provision of backup service. The AESO also considered that the contract capacity and ratchet structure of the proposed DTS rate to be a reasonable approach which balances facilities costs attributed to backup service and risk mitigation.<sup>229</sup>

DUC/TCE designed and proposed a standby rate,<sup>230</sup> which they submitted was designed to fit with the AESO's DTS rate and provide all load customers with equitable tariff treatment.

DUC/TCE submitted that the costs imposed by dual-use customers for standby services are significantly less than the costs imposed by other DTS customers. DUC/TCE considered the uniqueness of standby customers and suggested that it would be unduly discriminatory if a separate rate class were not provided for them. DUC/TCE argued that its evidence showed that its proposed standby rate will not result in subsidization between the DTS and the proposed standby rate classes.

IPPSA was generally supportive of the standby rate proposed by DUC/TCE, which it considered to be cost based, appropriately designed and necessary.<sup>231</sup> It suggested that the random nature and diversity of standby loads would contribute to lower system costs. Therefore IPPSA argued that the need for a separate standby rate is justified by the savings brought to the system overall and to encourage continued decentralization of generation and new generation development.

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<sup>227</sup> Application, Section 4, pp.31-32

<sup>228</sup> Ex. 005, Application, Section 4, p. 32-33

<sup>229</sup> Ex. 005, Application, Section 4, pp. 38 -39

<sup>230</sup> Ex. 236, DUC/TCE Standby Evidence

<sup>231</sup> IPPSA Argument, pp. 4-6

The ADC noted the position of the witnesses Dr. Rosenberg (on behalf of the ADC) and Mr. Drazen (on behalf of IPCAA) that continuation of the current DTS rate design would allow both an acceptable level of standby service as well as full service to be provided.<sup>232</sup> The ADC submitted that ratchets are a poor rate design feature for standby service. The ADC also submitted that ratchets would provide an undesirable signal as there would be very little incentive provided by the transmission tariff to rectify any on-site generator failure that required the customer to make use of standby service. IPCAA's position on the need for standby rates was similar to that of the ADC.

CCA/PICA's submitted that standby loads should be subject to contract requirements to not only recover bulk system costs; but to also recover local and POD costs. As in the case of the bulk system, the POD and local systems must be sized to accommodate unscheduled standby loads coming on the system. CCA/PICA stated POD and local systems must be planned for this purpose and the ratcheted NCP recovery proposed by the AESO would allow recovery of these costs. CCA/PICA maintained DUC/TCE's proposed un-contracted energy rate would not allow recovery of costs imposed on the POD and local systems by unscheduled standby loads

The AESO stated that, although the current DTS rate allows unscheduled usage, the ratchet provisions of the rate generally encourage customers to minimize backup service requirements. The AESO warned that it expected that a drastic reduction in the charges for use of backup service would encourage unscheduled loading and result in increased risks for system operations and reliability.<sup>233</sup> The AESO urged that, as the system operator, its concerns for system reliability not be ignored.

The AESO disagreed with DUC/TCE that standby loads should be attributed lower costs than more predictable loads. The AESO considered that consistent, long-term, and predictable usage patterns contribute to the efficient development of the bulk and local systems.<sup>234</sup> The AESO noted that standby loads are challenging to plan for, and therefore it did not agree with the submissions of IPCAA and DUC/TCE that standby loads should be attributed the minimal amount of bulk system costs.

Some parties contended that dual-use customers provide distinctive benefits to the AIES. However, the AESO suggested that these benefits arise due to the existence of generation (and not load). The AESO suggested that its tariff already allocates minimal costs to generation customers. It argued that the recognition of the benefits of generation on the transmission system has therefore already been taken into account and no further recognition is required for the load services at dual-use sites.

In response to IPPSA's submissions, the AESO stated that capacity in the bulk transmission system is being planned and built to accommodate backup and standby load. The AESO argued that the capacity exists whether or not backup and standby load is used in any specific month, and that it is therefore appropriate to charge those customers for that capacity through the proposed DTS rate.<sup>235</sup>

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<sup>232</sup> ADC Argument, p. 21

<sup>233</sup> Ex. 005, Application, Section 4, p. 34

<sup>234</sup> AESO Reply, p. 22

<sup>235</sup> AESO Reply, p. 25

The AESO stated that although load diversity on the bulk system suggests that bulk system charges should be less for backup or standby loads compared to normal loads, there is no similar diversity at the POD. The AESO noted that there is only one customer per POD, and there can be no diversity benefits where multiple customers may use the same POD capacity but at different times. Therefore the AESO considered that the position of DUC/TCE that a standby rate should have revenue neutrality at a 10% uncontracted load factor to the POD charges was unsupportable.<sup>236</sup>

The AESO considered that the position of DUC/TCE on the POD charges would result in the AESO receiving a materially lower POD-related revenue, although the same POD facilities would remain in place solely for the purpose of serving a specific customer. The AESO submitted that this would involve a transfer of POD-related costs from the standby customer to other customers, even though the POD facilities serve only the backup customer. The AESO argued that standby customers should remain subject to POD charges based on their peak metered demand or ratchet if they peak above their new contract demand.<sup>237</sup>

In Decision 2005-096, the Board stated:

The Board agrees with the parties that the development of a standby rate would be appropriate and may offer some flexibility to low load factor customers. However, the Board cautions parties that such customers impose significant costs with respect to the local system and POD costs and therefore, they must remain responsible for those costs.<sup>238</sup>

The AESO and CCA/PICA questioned whether the standby rate proposed by DUC/TCE would recover an appropriate amount of cost from the standby customers.<sup>239</sup> CCA/PICA has recognized that there is a low probability that all standby loads would require service at the same time. However, they argued that there was still a chance that standby loads could appear at times of stress on the system.

The Board notes that there is considerably less diversity on the local system and virtually none at the POD level.<sup>240</sup> The evidence contained in Ex. 113 indicates that the potential volume of low load factor standby load forecast to be present in the Fort McMurray area by 2016 is significant.<sup>241</sup> In relative terms, the volume of forecast low load factor load described in Ex. 113 will exceed the level of high load factor load. In absolute terms, it will exceed 1000 MWs. The Board finds this to be significant. In addition, the AESO indicated that a determination has not yet been made as to the proportions of the anticipated Fort McMurray area projects that will be deemed as system related costs, as opposed to customer related costs, for the purpose of the AESO's customer contribution policy.<sup>242</sup> Given this evidence, the Board shares the concerns of parties that the proposed standby rate may not recover, over the long term, the fixed costs caused by such standby loads.

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<sup>236</sup> AESO Argument, p. 55

<sup>237</sup> AESO Reply, p. 26

<sup>238</sup> Decision 2005-096, p. 30

<sup>239</sup> CCA/PICA Argument pp. 29-30, AESO Argument, p. 48

<sup>240</sup> TCCU, p. 33

<sup>241</sup> Ex 113, IPCAA.AESO-048(a) Attachment, page 17

<sup>242</sup> Tr. Vol. 4, pp. 809-816

DUC/TCE stated the following under cross-examination by counsel of the AESO:

“We believe that the standby rate would not be absolutely necessary if the existing charges for system costs were maintained in the 2007 tariff.”<sup>243</sup>

The Board has not approved the AESO’s proposed changes to the DTS rate. This appears to alleviate the primary concerns of customers who are concerned with the absence of a specific standby rate. Given the Board’s concerns that the proposed standby rate may not accurately reflect the costs that may be imposed on the system by the standby loads, the Board denies approval of the proposed standby rate. While denying this specific proposal, however, the Board acknowledges that a standby rate may be justified at a conceptual level and encourages the parties to continue considering the development of such a rate.

By way of letter dated July 13, 2007 DUC/TCE had requested that the Board strike a portion of the AESO’s argument concerning the standby rate on the grounds that it constituted new evidence. In arriving at its findings on the issue of the proposed standby rate, the Board did not consider or rely on the impugned portions of the AESO argument. Therefore, the Board finds it unnecessary to rule on whether or not those portions of the AESO argument constituted new evidence.

## **6 PHASE 2 MATTERS - OTHER RATES AND RIDERS**

### **6.1 Demand Opportunity Service (DOS) Rates**

The AESO proposed to continue to offer a DOS rate in order to utilize spare system capacity in an attempt to offset some of the costs which would otherwise be collected in full from its baseload DTS load customers. The AESO has had some form of DOS rate in place since 1996 to achieve this goal.

The DOS rate has traditionally been priced in a manner to entice customers who would not otherwise be willing to pay the full DTS rate to use the transmission system for certain portions of their energy requirement. While it is a discounted rate, the DOS rate has been designed such that customers would not be enticed to use the DOS rate as a replacement rate for the DTS rate for their base load.

In designing the DOS rate, the AESO examined each fixed and variable component of each DTS rate component to identify which costs it considered to be incurred in providing service to DOS customers. The AESO stated that the resulting minimum costs attributable to DOS 7 minute notice customers were contained in Table 4.7.2 of its application, reproduced below:

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<sup>243</sup> Tr. Vol 7, p. 1639

**Table 7. 2007 DTS Rate Components Attributable to DOS Loads (\$/MWh)**

DTS Rate Component	Fixed	Variable	Total
Interconnection – System	-	2.42	2.42
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	-	<b>4.71</b>	<b>4.71</b>

Source: Application Table 4.7.2 (Application Section 4.7, p. 41)

The AESO proposed that a contribution to fixed costs would not be recovered from its proposed DOS 7 minute rate, but would be recovered from its DOS 1 hour and DOS Term rates. The distinction was based on the relative ranking of each of the DOS service levels in its curtailment schedule.<sup>244</sup>

The AESO proposed that the DOS 1 hour rate be assigned 50% of the costs associated with DTS interconnection system fixed component, resulting in the following charges:

**Table 8. 2007 DTS Rate Components Attributable to DOS 1 Hour Loads (\$/MWh)**

DTS Rate Component	Fixed	Variable	Total
Interconnection – System	1.28	2.42	3.70
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	<b>1.28</b>	<b>4.71</b>	<b>5.99</b>

Source: Application Table 4.7.3 (Application Section 4.7, p. 43)

The AESO considered that the DOS Term rate should be assigned additional ratchet related costs not allocated to the DOS 7 minute and DOS 1 hour rates, resulting in the following charges:

**Table 9. 2007 DTS Rate Components Attributable to DOS Term Loads (\$/MWh)**

DTS Rate Component	Fixed	Variable	Total
Interconnection – System	19.08	2.42	21.50
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	<b>19.08</b>	<b>4.71</b>	<b>23.79</b>

Source: Application Table 4.7.4 (Application Section 4.7, p. 44)

The AESO noted that the final determination of the DOS rates would occur after the Board had ruled on its DTS rates.<sup>245</sup>

TCE proposed that the energy related share of costs should be based on the pure results from the TCCU, and not the final DTS rate design classification. The AESO did not agree.<sup>246</sup> The AESO considered that its recommended average and excess demand methodology applied to the

<sup>244</sup> Ex. 005, Application, Section 4, pp. 41-42

<sup>245</sup> Ex. 005, Application, Section 4, pp. 43-44

<sup>246</sup> AESO Argument, p. 57

classification of the entirety of system costs for its proposed DTS rate, and effectively replaced the classification in the Update.

The Board endorses the DOS rate as it uses excess system capacity, which would otherwise go unused, in exchange for revenues which offset the costs of all other customers.

The Board agrees that as a starting point, appropriate usage related costs should be recovered from DOS customers. While the Board also agrees that the same classification method should be used in identifying usage related costs for the DOS and DTS rates the Board has directed a classification methodology different from that proposed by the AESO. As such, the Board finds that the usage related costs approved by the Board in section 5.4.2 of this Decision (DTS Rate design) should form the basis of all DOS rates, including customers on 7 minute notice (DOS 7 minute rate).

The usage related cost allocation approved in section 5.4.2 of this Decision (18.0% of wires costs or 11% of total load costs) is much lower than that originally proposed by the AESO. The AESO had developed its DOS rate design using a combination of the TCCU and its A&E method. As such, the Board is concerned that a DOS 7 minute rate based only on usage may not provide a rate design which charges the appropriate amount for the value of the service being offered, and considers that the AESO should also collect a contribution towards fixed costs from this rate, as it had originally proposed for the DOS 1 hour and DOS term rates.

The Board therefore directs the AESO, as part of its refiling application, to propose an updated DOS 7 minute rate that is based on both usage costs, as approved by the Board, and a contribution to fixed costs. The Board expects the AESO to develop a proposed level for the DOS 7 minute rate that it considers appropriate and notes that a rate in the order of 6% lower than the current DOS 7 minute rate would be consistent with the overall DTS rate decrease of 6%.

With respect to the DOS 1 hour and DOS term rates, given the baseline values of usage and demand related costs assigned to these rates, the Board approved cost allocation would result in significantly different rates than those originally proposed by the AESO.

The Board therefore directs the AESO, as part of its refiling application, to propose new DOS 1 hour and DOS term rates, using the same concepts as contained in the DOS rate design section of its of the Application with respect to the cost differential it considers appropriate for all of its DOS rates, given their associated curtailment and contractual characteristics, and to indicate its rationale supporting those rates.

## **6.2 Fort Nelson Demand Transmission Service (FTS)**

In argument, the AESO explained that the Application proposed only minor changes to the FTS rate.<sup>247</sup> The AESO explained that the changes were simply to retain alignment with the provisions of the proposed DTS rate, since a fundamental principle behind the FTS rate is that it should largely (however not entirely) be the same as DTS.<sup>248</sup>

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<sup>247</sup> Exhibit 017, Application Appendix H - Blackline Tariff, p. 4

<sup>248</sup> As was referenced in BR.AESO-007

No party commented upon rate FTS. However, the Board has in this Decision directed that certain changes be made to the DTS rate. In particular the Board has directed changes to the classification of wires costs. To retain the alignment between rates DTS and FTS, the Board considers it may be necessary for the AESO to make changes to rate FTS in its refiling application. The AESO is therefore directed, in its refiling application, to review the Board directed changes to rate DTS and to propose any amendments necessary to rate FTS to retain alignment with rate DTS, and to indicate its rationale supporting its proposal.

### **6.3 Demand Under Frequency Load Shedding Credits**

The Application did not address Demand Under Frequency Load Shedding (UFLS) credits, but in argument,<sup>249</sup> the AESO stated that nothing had changed with its UFLS credits, no parties had objected, and therefore the Board should approve the UFLS credits as filed in its applied for rate schedules<sup>250</sup>.

The Board has reviewed the UFLS credits contained in the AESO's rate schedules and agrees that they have not changed from those approved in Decision 2005-096, and further notes that no parties had objected to their continued use. The Board approves the UFLS credits as contained in the AESO's rate schedules.

### **6.4 Rate Riders**

The AESO proposed only minor changes to clarify or correct some aspects of its rate riders.

The AESO clarified that the ratchet period in the DTS rate billing capacity calculation is the 24-month period ending with the current billing period, and included Rider F corrections applied for by the AESO in application 1482458 (which were subsequently approved by the Board in Order U2006-307) in the affected rate and rider schedules. In addition to certain other minor changes, information related to regulated generating units which was previously provided in Appendix B to the terms and conditions of service has been consolidated with the regulated generating units information already in the rate appendix.<sup>251</sup>

The AESO noted that the balance of the rates approved in the AESO's 2005-2006 GTA second refiling remained unchanged. A blackline comparing of the current and proposed rates was included in Appendix H of the Application.

No parties objected to the AESO's proposed rate rider changes.

The Board agrees with the AESO that these rate rider changes generally contain clarifications and corrections. In section 5.9 of in this Decision, the Board has requested that the AESO recalculate the impact of the Board approved tariff on the AESO's customers. The Board will therefore not approve the AESO's proposed Rider G at this time, which was designed to mitigate any rate shock related to the AESO's originally rate proposal. With this exception, the Board approves the rate riders as filed.

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<sup>249</sup> AESO Argument, p 64

<sup>250</sup> Ex. 008, Rate Schedules, p. 24

<sup>251</sup> Ex. 005, Application, Section 4, p. 53

## 6.5 Supply Transmission Service (STS) Rate Design

The STS rate is the portion of the AESO tariff used to recover certain costs from generators. The costs recovered from generators are line losses (which are based on location specific loss factors and pool price), and an interconnection charge (known as the Regulated Generating Unit Connection Charge, or RGUCC).

The AESO did not include an explicit section addressing the STS rate in the Application. Rather, the AESO stated that its STS was being reduced by 6.0%<sup>252</sup>, and included an updated STS rate schedule in its proposed rate schedules.<sup>253</sup>

The rate schedule updates included a revised RGUCC charge of \$303.88/MW/month, and precise wording which defined that location specific loss factors would be defined in accordance with ISO Rule 9.2.<sup>254</sup>

The AESO argued that it had provided the derivation of the RGUCC value in response to BR.AESO-18 (a), and that other than the ADC proposal that some wires costs, related to system optimization to reduce losses, be included in the STS tariff, no parties had raised any concerns or brought forth an alternate STS rate design.<sup>255</sup>

The AESO STS rate design has changed very little over the rate approved in Decision 2005-096. Further, the AESO provided the derivation of the RGUCC in BR.AESO-18(a).

The Board has reviewed this calculation and considers the AESO RGUCC appears to be reasonable. Further, the Board agrees with the AESO that the location specific loss factors used to calculate line losses are to be determined in accordance with the ISO Rule 9.2. The Board considers RGUCC related matters in section 8.7 of this Decision.

The Board has provided its reasons for rejecting the ADC proposal to add wires related system optimization costs to the STS rate in section 2 (Legislative Requirements) of this Decision.

The Board therefore approves the AESO STS rate contained in the STS rate schedule included in section 7 of the Application.

## 7 PHASE 2 MATTERS - EXPORT AND IMPORT RATES

### 7.1 XTS Rate

The AESO proposed a “non-recallable” rate (rate XTS) that would apply to customers exporting electric energy from the AIES over the Alberta-British Columbia or Alberta-Saskatchewan interties.<sup>256</sup> In Decision 2005-096, the Board encouraged the AESO to continue stakeholder

<sup>252</sup> Ex. 005, Application, Section 4, Table 4.0.1, p. 2

<sup>253</sup> Ex. 008, Application, Section 7, p. 26

<sup>254</sup> From the AESO website, [www.aeso.ca](http://www.aeso.ca): The Independent System Operator (ISO) Rules are designed to promote a fair, efficient and openly-competitive wholesale market for electricity in Alberta. The ISO is the term used in the Electric Utilities Act to refer to the operating company the Alberta Electric System Operator or AESO.

<sup>255</sup> AESO Argument, p 47

<sup>256</sup> Ex. 008, Section 7 of the Application, p. 12 of 129

discussions with interested parties to towards the potential development of firm import and export rates.<sup>257</sup>

The AESO based the proposed rate XTS on its proposed DTS rate. This meant that the proposed rate XTS reflected DTS rate components (except for exclusion of the POD charge from rate XTS) expressed on a usage basis.<sup>258</sup> Minor revisions were subsequently made to the proposed XTS rate schedule in an AESO errata filing.<sup>259</sup>

The proposed XTS rate would require a minimum contract term of 1 year. The AESO indicated that it would consider capacity contracted under the XTS rate in its transmission system planning decisions.<sup>260</sup> The AESO also noted that while customers would be required to contract for XTS capacity for the full contract term, capacity would only be available in hours in which Available Transfer Capacity (ATC) exists to accommodate the capacity. The AESO indicated that it did not intend to charge customers under rate XTS for any hour in which the ATC was not available to accommodate scheduled transfers.

TCE submitted that the AESO's proposed XTS rate should be rejected because it would not properly reflect cost causation and would not provide an appropriate level of firmness of service.

Depending on the definition used, TCE noted that during August to December of 2006, ATC was not available for 25% to 40% of on-peak hours. It further noted that during the January to July period, ATC unavailable for 90% of hours. TCE submitted that while exports booked under rate XTS would have a higher scheduling priority than Rate XOS, rate XTS effectively provided the same level of service as Rate XOS except during times of limited availability rather than complete unavailability of ATC. TCE argued that the 20-40% of hours when ATC tends not to be available may be the most profitable hours for exports, such that the AESO's proposed XTS rate would not be appealing to either exporters or their counterparties in light of the opportunity service rate already available. TCE argued that if a so-called firm service is not always available, it is really only an opportunity service. As such, there would be no reason for an exporter to pay a premium beyond the cost of XOS rates except to obtain a higher priority than other opportunity exports.

TCE expressed concern with the AESO's proposal that commitments for firm service would be used as a signal to provide additional capacity on the transmission system. TCE also expressed concern with the absence of a "use it or lose it" provision in the rate to avoid potential abuse of rate XTS for the purposes of blocking export transactions from Alberta.<sup>261</sup>

TCE expressed concerns about issues of consistency with other jurisdictions (seams issues)<sup>262</sup> and was not confident that these issues could be resolved to the satisfaction of the parties outside of the tariff. For this reason alone, TCE submitted that approval of rate XTS would be premature. Powerex and IPPSA expressed similar concerns.

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<sup>257</sup> Ex. 005, Section 4.8 of the Application, p. 44; Decision 2005-096, p. 35

<sup>258</sup> Ex. 005, Section 4.8.1 of the Application, page 46, Ex 008, Section 7 of the Application, pp. 12-13 of 129

<sup>259</sup> Ex. 382, AESO Errata Filing no. 2 dated May 10, 2007

<sup>260</sup> Tr. Vol. 3, p. 601

<sup>261</sup> Ex. 242, TCE Evidence, p. 46, cited in Powerex Argument at p. 26

<sup>262</sup> Powerex-TCE 8 and Powerex-TCE 9; see also Exhibit 126, TCE.AESO-52(c), cited in Powerex argument at p. 26

TCE submitted rate XTS should be denied and the AESO should be directed to work with exporters to develop a firm export rate. TAU, Powerex and IPPSA made similar submissions.

Powerex noted that the design of rate XTS relied on the same cost basis as Rate DTS (except for the exclusion of the POD charge from rate XTS). However, Powerex noted that the level of ATC currently available is not sufficient to offer firm export service on the British Columbia- Alberta intertie line line.<sup>263</sup> It also submitted that since rate DTS would remain a higher priority service than rate XTS, and since the AESO has not committed to dispatching out-of-merit generation to maintain rate XTS service (as it would for DTS service), the proposed rate XTS offered a lower quality service but at full firm service rates.

With regard to the AESO's assertion of 80% availability of 100MW ATC, Powerex argued that 80% availability is poor even for an interruptible service, and much less so for a firm service. Powerex noted that the AESO had not guaranteed that it would dispatch Transmission Must Run (TMR) to meet the needs of XTS customers (as it would for DTS service). Powerex argued that instead, the AESO only indicated that using TMR for this purpose was still under discussion in its ATC working group. Absent such assurances, Powerex submitted that it would not be reasonable to set firm export rates at a level equivalent to domestic service rates.

IPPSA argued that the AESO's proposed rate XTS was flawed for several reasons, including that the level of firmness was not acceptable, given the evidence of the limited availability of ATC. It also submitted that the market for XTS service was not fully developed and that the proposed cost of rate XTS would likely not justify its use. IPPSA also questioned the appropriateness of a one year commitment period in the absence of a developed market. IPPSA considered that the AESO was attempting to sell an interruptible service under a firm service rate.

TAU submitted that the AESO's approach of aligning the XTS and DTS rates appeared to be flawed since the postage stamp requirements set out in subsection 30(3)(a) of the EUA do not apply to exporters.

In reply, the AESO argued that whereas several parties had opposed the approval of the proposed XTS rate, no party had offered an alternative proposal. The AESO noted that given the positions of interveners, parties would be unlikely to use the proposed XTS rate, and that elimination of the rate from the 2007 tariff would likely have little practical impact. However, the AESO submitted that its proposed XTS rate was reasonable and cost based and noted that participants in this proceeding would not represent all potential users of the service.

The AESO stated that it would expect to consult with stakeholders on modifications to the firm export rate, if required, as and when continuous availability of export capacity becomes more likely. Given that it is unknown when such export capacity may become available, the AESO submitted that it would be premature for the Board to provide specific direction regarding the development of a firm export tariff.

TAU argued that the availability of at least 100 MW of ATC for about 80% of the time during the last quarter of 2006 was significantly different from the availability and nature of DTS

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<sup>263</sup> Tr. Vol. 3, p. 599

service. TAU submitted that Rate DTS service levels should comply with the so-called “100% / 95% capability” set out in section 15(1)(e) of the *Transmission Regulation*. TAU noted that section 16 of the 2007 *Transmission Regulation* requires the restoration of intertie capacity, and that such restoration by 2009 is doubtful.

In light of these considerations, TAU submitted that the approval of a firm rate for export service premised on a cost allocation matching that of firm DTS service would not reflect the facts of the system and would therefore be inappropriate. TAU also expressed concern that, if adopted, the AESO’s proposed XTS rate would become the status quo for any further consideration of a firm export service rate.<sup>264</sup>

The Board will assess the issues raised by parties in respect of the proposed XTS rate first by reviewing the legislative requirements, and second by considering whether the level of reliability of the export service might justify approval of the rate, in light of the seams and implementation issues raised by interveners.

### 7.1.1 Legislative Requirements

The Board considers that the proposed rate XTS must be assessed bearing in mind three possible situations: restoration of an existing export intertie path to its rated capacity, establishment of a new intertie, and expansion or upgrade of an existing intertie to a rating that exceeds its rated capacity.

With regard to restoration of an intertie to its rated capacity, the Board stated in Decision 2005-096 that:

The Board has reviewed Subsection 8(1)(g) of the *Transmission Regulation*, dealing with the restoration of the intertie to its rated capacity. The Board considers that the AESO has an obligation pursuant to the *Transmission Regulation* to make rules and to take measures to expand or enhance the transmission system in order to restore the path rating of the interconnections however, the regulation does not impose a time frame nor does it dictate the method in which this must be achieved. This provision is not a required matter to be included in the tariff under the regulation. Rather, it is part of the rule making authority conferred on the AESO. The Board therefore does not consider that the AESO is in breach of this section of the regulation should it choose not to pursue the development of import and export tariffs to the extent desired by parties in this proceeding. The Board notes, with encouragement, the fact that the AESO has invited significant stakeholder consultation in this process, as shown by the evidence in this proceeding.<sup>265</sup>

Subsection 8(1)(g) of the 2004 *Transmission Regulation*,<sup>266</sup> which was in effect at that time, provided that:

8(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must  
...

<sup>264</sup> TAU Reply Argument, p. 4

<sup>265</sup> Decision 2005-096, p. 35.

<sup>266</sup> Transmission Regulation, AR 174/2004

- (g) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside Alberta can import and export electricity on a continuous basis, at or near the transmission facility's path rating

Section 16 of the 2007 *Transmission Regulation* sets out the obligation of the AESO to restore existing interties to their path ratings. This provision reads as follows:

**16(1)** In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

**(2)** The plan to restore interties to their path ratings must specify how the ISO intends to restore and maintain each intertie to, or near to, its path rating without the mandatory operation of generating units.

**(3)** The plan to restore and maintain interties must be incorporated into and form part of the transmission system plan as soon as practicable.

While subsection 16(3) of the 2007 *Transmission Regulation* now specifies that the AESO must prepare a plan and make arrangements for existing intertie path rating restoration “as soon as practicable,” the Board finds that the regulation does not impose a specific time frame nor does it dictate the method in which this must be achieved. The Board finds that this provision is not a required matter to be included in the tariff under the regulation, but rather is part of the rule making authority conferred on the AESO. The Board considers that the AESO is not in breach of this section of the regulation should it choose not to pursue the development of import and export tariffs to the extent desired by parties in this proceeding.

With respect to the allocation of costs related to path restoration intertie projects, this matter was addressed in Decision 2005-096 on the basis of principles set out in the 2003 discussion paper entitled “Transmission Development: The Right Path for Alberta” (the Transmission Development Policy or TDP).<sup>267</sup> The Board stated in Decision 2005-096, with reference to generator remedial action schemes (GRAS) that:

In light of the foregoing, therefore, the Board will not direct the AESO to implement a GRAS as part of this Decision. However, the Board does agree with TCE that the Transmission Development Policy clearly indicates that the costs of internal reinforcements and RAS arrangements necessary to allow the interties to operate at their design capacity are to be allocated to load, irrespective of whether the RAS arrangement is export or import related.<sup>268</sup>

The Board finds that the rationale for allocating those costs to load applies beyond GRAS, and applies equally to restoration of an intertie within the meaning of section 16 of the 2007 *Transmission Regulation*. Allocating these costs to load is also consistent with the Transmission Development Policy, which indicated that the cost for internal reinforcements and RAS arrangements to allow the interties to function as designed are to be allocated to load.<sup>269</sup>

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<sup>267</sup> Ex. H-008

<sup>268</sup> Decision 2005-096, p. 37

<sup>269</sup> Ex. H-008, p. 9

The Board finds that in the context of restoration of interties within the meaning of section 16 of the *2007 Transmission Regulation*, both the cost of facilities and operational measures on the interties themselves as well as any internal reinforcements within the Alberta transmission system are to be included within the set of costs allocated to rate DTS rather than being specifically identified and allocated to rate XTS.

The Board further notes that while the AESO has indicated that that it intends to use rate XTS contract sign-ups as a signal or trigger for transmission system planning purposes,<sup>270</sup> this approach appears to be inconsistent with the legislative and regulatory framework in at least two major respects. In particular, section 16 of the *2007 Transmission Regulation* places an obligation on the AESO to make arrangements to relieve any constraints on the transmission system that may be preventing full utilization of the existing interties to their designated path ratings. Accordingly, the Board finds that the AESO's obligation to restore existing interties to their path ratings is not tied to contracting for firm export service by AESO customers.

In contrast, the Board is concerned that relying on contracting for rate XTS as an indicator of need could result in the construction of new system capacity for the primary benefit of importer or exporters that would not otherwise be built. In particular, the Board is concerned that if the aggregate firm export service capacity contracted for by customers exceeded the capacity required to restore existing interties to the path ratings, the costs of such additional system capacity could be borne by DTS customers without the regard to a benefits tests discussed in both subsection 27(4) of the *2007 Transmission Regulation* and the Transmission Development Policy.

With regard to new interties, or upgrades or enhancements to an intertie that proposes or would result in an increase to the path rating (each, "non-restoration" interties), section 27 of the *Transmission Regulation* is applicable. This provision reads (in part):

**Intertie projects**

**27(1)** This section applies to the following:

- (a) an intertie proposed to be constructed;
- (b) an upgrade or enhancement to an intertie that proposes, or would result in, an increase to the path rating of the intertie.

...

**(4)** The cost of planning, designing, constructing, operating and interconnecting an intertie to which this section applies must be paid by

- (a) the person proposing the intertie, and
- (b) other persons to the extent that they directly benefit from the intertie, based on the use described in the needs identification document approved by the Board, and then only to the extent permitted by the ISO tariff.

**(5)** A person proposing an intertie to which this section applies, in accordance with the ISO rules, must

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<sup>270</sup> Tr. Vol. 3, pp. 601-602

- (a) provide open access to market participants by auction or other transparent process, and file the terms and conditions respecting open access with the Board for information, and
  - (b) provide that the intertie be available in an open and non-discriminatory manner, similar to the access available to other transmission facilities.
- (6) The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the intertie referred to in this section for import or export of electric energy to or from Alberta.

Subsection 27(4)(a) provides that the costs of non-restoration intertie projects are to be borne by the person proposing the intertie. Subsection 27(4)(b) further provides that such costs may be shared with other persons only to the extent that they *directly* benefit from the intertie, and then only to the extent that the benefit is identified in a Board approved needs identification document, and only to the extent permitted by the AESO tariff. The Board considers that the burden of demonstrating residual direct benefits from a non-restoration intertie project within the meaning of section 27(4) of the 2007 *Transmission Regulation* generally lies with the person proposing the intertie.

Furthermore, while subsection 27(6) of the regulation requires the AESO to include rate and terms and conditions for the use of the Alberta interconnected system to access non-restoration intertie facilities for the import or export of electric energy to or from Alberta, those rates and terms and conditions must be “appropriate for the class of service.”

The Board considers that a rate appropriate for this class of service must be determined with regard for cost allocation principles set out in subsection 27(4). The Board finds that the proposed XTS rate does not comply with subsection 27(4) or subsection 27(6) criterion by virtue of the fact that the different cost sharing principles applicable to intertie path restoration costs and non-restoration intertie project costs are not appropriately reflected in the proposed rate. The Board finds that XTS rate must be denied on this basis.

### 7.1.2 Additional Issues Raised By Parties

Several of the concerns raised with the proposed Rate XTS give rise to additional concerns.

The Board agrees with the observations of several parties that the curtailment priority assigned to service under rate XTS and the anticipated availability of sufficient ATC during the term that the tariff is expected to be in effect is not consistent with the notion of a firm service. In general, the Board agrees with the view expressed by TAU in its reply argument that the availability of a firm service should reflect the standard set out in section 15(1)(e) of the 2007 *Transmission Regulation*. The Board does not agree with the AESO’s suggestion that even though export intertie ATC is not likely to be fully available during the anticipated term of the tariff, the level of service that would be available for potential users of rate XTS would justify establishment of a rate described as a firm service rate.

Although Powerex commented on the absence of an AESO commitment to dispatch generators out-of-merit to the extent necessary to provide a firm export service,<sup>271</sup> the Board considers that this is a matter within the AESO's rulemaking powers pursuant to section 17 of the *Transmission Regulation*. Accordingly, the Board considers that it is not necessary or appropriate for the Board to direct the AESO to incur out-of-merit costs to ensure that truly firm export service rate is available during the expected effective period of the tariff.

The Board recognizes that the curtailment priorities stated in the XTS and XOS rate schedules attach a moderately higher degree of firmness of service to rate XTS than rate XOS,<sup>272</sup> and that for this reason Rate XTS would tend to have a somewhat higher value to customers than Rate XOS. The Board does not consider that, absent legislative considerations, this would have been a sufficient basis upon which to have approved proposed rate XTS, given the seams issues and current administrative complexity of implementing such a rate.

A concern raised by TAU was that any firm export service rate that might be approved by the Board might be viewed as the "status quo" for the purposes of addressing seams issues and other export service business practices.<sup>273</sup> The Board considers that withholding approval of proposed rate XTS would provide greater freedom to the AESO and parties to address any issues that may be raised in future stakeholder discussions and to best align the nature of export services offered with the costs allocated to the service within a proposed AESO tariff rate.

In reply argument, the AESO stressed the value of continuing to develop an Open Access Same Time Information System (OASIS) or other similar system, regardless of whether its proposed rate XTS is approved. Given that certain rates approved in this Decision may depend on completion of an OASIS or similar system, nothing in this Decision requires the AESO to offer rates approved in this Decision prior to implementation of the OASIS system. If for this reason the AESO does not intend to offer one or more rates approved in this Decision, the Board directs the AESO to identify those rates at the time of its refiling application.

As cost causation is strongly related to whether the service is curtailable or essentially firm, the Board encourages the AESO to resolve the anticipated level of firmness of the service to be provided, prior to proposing an export rate in future tariff applications.

## 7.2 Import Export Opportunity Service Rates

In the Application, the AESO noted that in consultations, some stakeholders requested an extensive selection of export rates (hourly, daily, weekly, monthly, and annual versions, for both non-recallable and opportunity service). However, the AESO stated that it understands that in neighbouring jurisdictions, the majority of export transactions occur on hourly, monthly, and annual rates. Therefore in the Application, the AESO proposed hourly and monthly opportunity export rates (proposed rates XOS 1 Hour and XOS 1 Month). The proposed XOS rates would replace the current EOS rate and would be applicable to customers who export electricity from the AIES over the Alberta- British Columbia or Alberta-Saskatchewan inter-ties.<sup>274</sup>

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<sup>271</sup> Powerex Argument, p. 25

<sup>272</sup> Ex 008, Application, section 7, rate schedules at pages 12, 14, 16 of 129

<sup>273</sup> TAU Reply Argument, p. 4

<sup>274</sup> Ex. 008, Application, Section 7, pp. 14-17 of 129 (Rate XOS 1 Hour and Rate XOS 1 Month)

Export rate component charges are proposed to be based on similar components as for the DTS rate. Similar to the AESO's DOS rate proposals, the AESO proposed that all export rate components will be charged on a usage (\$/MWh or percentage of pool price) basis. The AESO therefore converted all components of its 2007 DTS revenue requirement into usage charges as if all were to be recovered on such a basis from all DTS customers.<sup>275</sup> The fixed and variable component of each DTS rate component was then examined to determine which costs should be included in export rates.<sup>276</sup>

### 7.2.1 Export Opportunity Service (XOS) Rates

The AESO proposed that export opportunity service Rates XOS 1 Hour and XOS 1 Month be recallable services similar to DOS rates (DOS 7 Minutes and DOS Term). The AESO noted that all scheduled export capacity must be confirmed at 20 minutes before the hour in accordance with AESO Operating Policies and Procedures (OPPs). The AESO stated that XOS capacity will be curtailed immediately prior to curtailment of opportunity domestic loads.<sup>277</sup>

The XOS rates were designed to recover all variable costs and also a contribution to fixed costs, to reduce the average level of rates charged to other customers.<sup>278</sup> The resulting costs attributable to Rate XOS 1 Hour and to Rate XOS 1 Month were presented in the Application.<sup>279</sup>

TCE submitted extensive evidence on export rates.<sup>280</sup> TCE considered that in its pricing of export rates, the AESO had incorrectly assigned fixed costs that are allocated on the basis of energy as if they were true variable costs that were properly allocated by energy. It also considered that the AESO allocated too many operating reserve costs to opportunity exports. TCE stated if cost of service was the main driver for pricing opportunity export rates, there would be a price reduction in the export opportunity rates. Based on its value of service criterion, TCE considered that an increase in export opportunity rates was required. TCE maintained the proper pricing of opportunity exports required an incremental or marginal cost analysis, combined with a value of service adjustment, to determine the appropriate contribution to fixed costs to be charged to the opportunity rate class. TCE proposed XOS 1 Hour and XOS 1 Month rates that are 10% and 20% respectively higher than the current EOS rate.<sup>281</sup>

The AESO also noted TCE suggested<sup>282</sup> black start services should not be attributed to XOS rates. The AESO considered that all services benefit from the ability to restore electrical supply in a timely manner on the transmission system in the unlikely event of a blackout. Black start services are considered a variable costs charged to DTS customers as a usage (\$/MWh) charge. The AESO submitted it was reasonable to include that charge in the XOS rates. The Board agrees with, and approves, the allocation of blackstart services costs to the XOS rates on this basis.

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<sup>275</sup> Ex. 005, Application, Section 4, Table 4.8.2, p. 46

<sup>276</sup> Ex. 005, Application, Section 4, Table 4.8.1, p. 45

<sup>277</sup> Ex. 005, Application, Section 4, p. 48, lines 43-44

<sup>278</sup> Ex. 005, Application, Section 4, Tables 4.8.4 and 4.8.5, pp. 48-49

<sup>279</sup> Ex. 005, Application, Section 4, p. 49

<sup>280</sup> TCE Evidence, pp. 33-46 & Appendix H

<sup>281</sup> TCE Evidence, p. 36, Figure 4

<sup>282</sup> Ex. 242, TCE Evidence, p. 46, lines 9-15

With respect to operating reserve costs, TCE maintained that the very nature of an opportunity service that it is only available when DTS customers are not otherwise using the bulk transmission system. TCE considered that the system planners do not plan for opportunity loads, and that opportunity loads have not created any embedded transmission system costs<sup>283</sup> but that the AESO's calculation of the reserve charge to opportunity service appears to involve embedded costs.<sup>284</sup> TCE noted the AESO explained that significant reserves were required even if there are no opportunity sales.<sup>285</sup>

TCE explained that it undertook an analysis of the export transactions to determine what additional operating reserves were actually incurred. Every hour was examined to identify the amount of spinning reserve in excess of the largest contingency on the system. Since the AESO must purchase operating reserves for the largest contingency regardless of exports, TCE maintained only exports which increase the load to a point where extra operating reserves are required should be considered in an incremental cost analysis. While not all spinning reserves in excess of the largest contingency are required because of exports, TCE adopted this conservative assumption. Even with this assumption, TCE found that only 9% of the export energy will potentially be required for spinning reserves. TCE also assumed that 9% is also a reasonable estimate of the requirement for supplemental and regulating reserves. TCE recommended that exports should be allocated costs for 9% of the operating reserves that would be allocated to a firm load customer on a per KWh basis. This results in a reduction of the operating reserve charges from \$2.29 per MWh to \$0.21 per MWh.<sup>286</sup>

The AESO maintained that in proposing that the XOS rates be allocated only 9% of the operating reserve costs that are allocated to rate DTS, TCE misunderstood the AESO's operating reserve requirements. In an undertaking<sup>287</sup> to TCE, the AESO confirmed that all export energy will require additional operating reserves, to a level similar to that required for firm load demand. The AESO explained that it regularly procured operating reserves as part of its ordinary requirement to support export services. The AESO submitted that simply because Part 2 of the XOS rates allows an incremental charge to be levied against export customers, at the discretion of the AESO, this should not preclude the inclusion of a standard charge for these services being built into Part 1 of the XOS rate.

Powerex, IPPSA and TAU generally supported the concerns of TCE. Powerex in particular submitted extensive argument on the proposed XOS 1 Hour rate, noting that the system was not planned to accommodate opportunity sales. Therefore opportunity sales should not be assigned any of the fixed costs incurred to expand the system.<sup>288</sup> With respect to operating reserves, Powerex submitted that the AESO should charge only the incremental costs of reserves and maintained that the current wording in the tariff is appropriate.<sup>289</sup> Powerex accepted the recommendations of TCE with respect to XOS 1 Month.

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<sup>283</sup> Ex. 242, TCE Evidence, Appendix F, p. 5, lines 31-33

<sup>284</sup> Ex. 005, Application, Section 4, Table 4.7.1, p. 40 and TCE Evidence (Ex. 242) p. 42

<sup>285</sup> Ex. H-022, where AESO's Operating Policy and Procedure 402 is discussed.

<sup>286</sup> TCE Argument, pp. 55-56, also Ex 242, TCE Evidence, p. 42

<sup>287</sup> Ex. H-022, Undertaking No. 3

<sup>288</sup> Powerex Argument, p. 33

<sup>289</sup> Powerex Argument, p. 38

The Board considers that opportunity service should be priced at no less than incremental variable cost of providing the opportunity service, and that opportunity service rates should also reflect the value of the opportunity service to the customer.

The two primary areas of disagreement among parties with respect to pricing of opportunity service relate to the AESO's determination of variable or energy related costs as a result of its proposed A&E methodology and the AESO's determination of reserve costs.

With respect to the determination of the variable or energy related portion of wires costs allocated to opportunity service, the Board has in section 5.4.1 of this Decision rejected the use of the A&E methodology and directed a much lower energy related classification in the DTS rate. The finding regarding the lower energy classification must also be reflected in the pricing of export opportunity services to ensure that such opportunity service rates will, at minimum, be priced above variable cost. This acknowledges that a rate priced below variable cost would be subsidized by domestic customers, which is not in accordance with the principle of cost causation.

Incorporating the Board's findings with respect to the A&E method results in a significant reduction in the minimum charge. By way of comparison, the figures presented by the AESO in the Application<sup>290</sup> for the variable costs of connecting to the system are based upon the AESO's proposed classification of costs using the A&E method.<sup>291</sup> This resulted in approximately 50% of wires costs being classified as energy related. The energy classification directed by the Board, however, is to result only in 18% of wires costs being classified as energy. The Board therefore expects the \$2.42/MWh shown by the AESO in Tables 4.8.4 and 4.8.5 of the Application as amount of variable cost to be allocated to opportunity service to drop to less than \$1/MWh.<sup>292</sup> The Board has also reviewed the revised Schedule 5.8 provided by TCE in its evidence and notes that TCE's calculations may closely approximate what the Board's cost of service based allocation might be, for the purposes of establishing a minimum charge.

With respect to the allocation of reserve costs to opportunity service, the AESO has performed a calculation that allocates an amount equal to the embedded cost of reserves to opportunity service.<sup>293</sup> The Board considers this to be inappropriate as opportunity service should only be allocated incremental costs. Powerex has advocated that no direct costs for reserves be allocated to opportunity service. The Board does not consider this approach will reasonably recover the appropriate amount of cost. The Board considers the most credible evidence regarding the allocation of reserve costs for the purpose of determining the minimum charge to be that of TCE.<sup>294</sup> TCE's calculations were performed on an incremental basis, and the Board considers they most appropriately represent the costs incurred to provide opportunity service. The pricing of reserves as calculated by TCE, along with the discretion afforded to the AESO by the current wording in the existing tariff,<sup>295</sup> will in the Board's view result in recovery of the incremental costs incurred to provide opportunity service.

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<sup>290</sup> Ex. 005, Application, Section 4, p. 49, Tables 4.8.4 and 4.8.5

<sup>291</sup> Ex. 005, Application, Section 4, p. 48, item (a) and p. 46, Table 4.8.2

<sup>292</sup> AESO calculation based on 50% energy related, if reduce to 18% calculation is  $(.18/.50)*\$2.42 < \$1$

<sup>293</sup> Ex. 005, Application, Section 4, Table 4.7.1, p. 40

<sup>294</sup> TCE evidence, Figure 4, p. 36

<sup>295</sup> Ex. 008, Proposed Tariff, p. 14, lines 32-35 and p. 16, lines 32-35

Based upon the calculations provided by TCE, the incremental costs assigned to opportunity export services for the purpose of setting a minimum charge<sup>296</sup> is below the current EOS Rate. However, as stated above, opportunity rates should also reflect value of service.

In its evidence, TCE proposed<sup>297</sup> an XOS 1 Hour Rate with a price 10% higher than the current EOS Rate and an XOS 1 Month Rate 20% higher than the current EOS Rate. As it is evident that TCE's proposed rates would exceed the incremental costs associated with opportunity export service, the Board considers that the rates proposed by TCE provide reasonable measure of the value of these services and would make a contribution to fixed transmission wires costs. The Board also notes that it has allowed the addition of black start costs to opportunity rate costs. The Board considers these costs to be minimal,<sup>298</sup> however, and can be recovered within the rates proposed by TCE.

Therefore, in accordance with figure 4 on p. 36 of TCE's evidence, the Board finds that the minimum charge in Rate XOS 1 Hour is to be set at \$3.98 per MW/h and that Rate XOS 1 Month is to be set at \$4.36 per MW/h. The AESO is directed to make all necessary adjustments to its export opportunity rate schedules and any associated T&Cs to reflect the above findings at the time of its refiling application.

### 7.2.2 Import Opportunity Service (IOS) Rate

The AESO stated that in stakeholder consultations, it had initially proposed to develop non-recallable and opportunity import rates. However, non-recallable and opportunity distinctions do not exist for the AESO's domestic supply service. There likewise appeared to be no basis upon which to differentiate between non-recallable and opportunity import rates. Rate IOS recovers only the cost of losses and a transaction fee.

The AESO therefore proposed to continue the IOS rate as previously approved by the Board.

No party expressed any concern with respect to this rate. The Board finds the AESO proposal to be reasonable and it is approved as filed.

### 7.3 Merchant Service Rates

In the Application, the AESO noted that although it had initially proposed to develop rates for export and import service over merchant transmission lines using a point-to-point (rather than a network) service model, it ultimately decided to base its proposed rates for merchant services on a network service model.<sup>299</sup> The proposed merchant service rates (Rates MTS, MOS 1 Hour, MOS 1 Month) would apply to customers exporting electric energy from the AIES over an intertie other than the Alberta-British Columbia and Alberta-Saskatchewan interties.<sup>300</sup>

The proposed merchant service rates are similar in structure to the proposed DTS rate. However, the AESO noted that while the proposed XTS rates included a contribution to the costs of the

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<sup>296</sup> Ex. 242, TCE Evidence, Figure 4, p. 36

<sup>297</sup> Ex. 242, TCE Evidence, Figure 4, p. 36

<sup>298</sup> Application, Schedule 5.1, Black Start only \$2.8 million of \$644.9 million revenue requirement allocated to DTS

<sup>299</sup> Ex. 005, Application, Section 4.9, p. 50

<sup>300</sup> Ex. 008, Section 7 of the Application, pages 18, 20 and 22 of 129

Alberta-British Columbia and Alberta-Saskatchewan interties, these facilities would not be used for energy transfers over a merchant line. Accordingly, the AESO proposed to exclude both the fixed and variable wires costs attributable to the existing interties from rates applicable to service over the AIES for export using merchant interties. The AESO noted that it had not proposed to recover intertie costs through its proposed Rate IOS, and that Rate IOS would apply to imports over merchant transmission facilities without modification.

A description of the AESO's conversion of fixed and variable intertie cost components into \$/MWh amounts in Application Figure 4.9.1. A summary of the AESO's derivation of its proposed merchant service rate schedules was provided in Application Schedule 5.8.<sup>301</sup> Minor revisions to the AESO's proposed merchant rate schedules as initially set out in section 7 of the Application were subsequently set forth in an AESO errata filing.<sup>302</sup>

While the submissions of interveners did not generally focus on merchant service rates, the Board recognizes that many arguments provided in respect of XTS and XOS rates are also applicable to the design of merchant transmission service rates. Accordingly, the Board has taken parties' views regarding other export and import service rates into account when considering its findings in respect of merchant service rates, as applicable.

The Board deals with the proposed MTS and MOS rates in separate sections below.

### **7.3.1.1 Merchant Transmission Service (Rate MTS)**

The Board notes that the MATL project will not be completed within the anticipated effective period of the AESO's 2007 tariff. As a result, the Board considers that the primary value in considering the proposed merchant transmission service rates in this Decision would be to provide an indication to future potential users of the prospective MATL intertie as to how they would be charged for using the Alberta transmission system to access the prospective MATL line.

As previously discussed in section 7.1.1 of this Decision, by virtue of subsection 27(1) of the 2007 *Transmission Regulation*, the remainder of section 27 applies to upgrades or enhancements resulting in increases to the path ratings of existing interties as well as to new interties proposed to be constructed. Subsection 1(1)(d) of the 2007 *Transmission Regulation* defines an intertie to mean "a transmission facility, including its associated components, that links one or more electric systems outside Alberta to the interconnected electric system." Neither subsection 27(1) nor subsection 1(1)(d) differentiates between new interties proposed by the AESO and merchant interties. Accordingly, the Board's findings regarding section 27 of the 2007 *Transmission Regulation* discussed in section 7.1.1 of this Decision are also generally applicable to the evaluation of the AESO's proposed merchant transmission service rates.

In section 7.1.1, the Board found that a key principle arising from subsections 27(4) and 27(6) of the 2007 *Transmission Regulation* is that the costs arising from an intertie project are to be borne by the person proposing the intertie and should be shared with other persons only if, and to the extent that they directly benefit, section 27(4)(b) is otherwise satisfied. There is no guarantee that any merchant rate that may be approved in the future will approximate rate MTS as proposed by

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<sup>301</sup> Ex. 006

<sup>302</sup> Ex. 382, AESO Errata Filing no. 2 dated May 10, 2007

the AESO in the Application, particularly if it is found that the incremental costs of providing the service are greater than the costs reflected in the proposed rate MTS.

During cross-examination by Board counsel, Mr. Martin on behalf of the AESO indicated that the AESO did not expect to invoice the developers of the MATL project for system impacts beyond the physical interconnection facilities for the MATL project itself.<sup>303</sup> An exchange also took place between Board counsel and Mr. Martin regarding the AESO's proposed treatment of potential incremental "deep system" costs that might be necessary to provide firm service to customers wishing to use the MATL intertie. If additional firm service MTS customers signed on to use the MATL intertie and the AESO determined that some incremental firm load from those additional customers resulted in a need for expenditures on additional facilities on the AIES, the AESO was asked if in those circumstances it intended to pass along those costs to either MATL or the MTS customers. The response was no, that additional facilities on the AIES that are deep-system facilities are shared by many customers. The AESO anticipated treating them in the same way as it does any other firm service, such that those costs would be shared by all users on the system and recovered through the rate itself as opposed to as an upfront contribution.<sup>304</sup>

This exchange revealed that the AESO considers that it has discretion to assess incremental system costs against an individual customer contracting for firm merchant transmission service. However, the it expects that incremental system costs caused by providing a level of firm service to or from the MATL intertie would generally be shared by all users on the system and recovered through the DTS rate rather than through an upfront contribution to be paid by the merchant intertie developer or from users of the intertie through the inclusion of incremental deep system costs within rate MTS.

Noting the AESO's intention that an approval of the proposed MTS rate should serve as an indication of what a potential MTS customer would expect to pay, the Board is concerned that an approval of the proposed MTS rate in light of the exchange referred to above could be misunderstood by potential MTS customers. In particular, consistent with the Board's findings on proposed rate XTS, the Board considers that to the extent that incremental costs (including incremental deep system costs) may be caused by providing service to customers seeking rate MTS service, section 27 of the 2007 *Transmission Regulation* specifically requires such costs to be allocated among the person proposing the intertie and the customers that fall within the meaning of section 27(4) (rather than shared with other load customers such as DTS customers). Presently, however, the incremental cost arising from system reinforcements necessary to provide firm service from or to MATL is unknown.<sup>305</sup> As such, there is no basis to conclude that incremental deep system costs arising from actions taken by the AESO to reinforce the Alberta transmission system to accommodate transmission service from or to MATL would reasonably correspond to any future merchant rate that may be proposed.

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<sup>303</sup> Tr. Vol. 3, p. 722, lines 11-20

<sup>304</sup> Tr. Vol. 3, p. 725, lines 6-25, p. 726, and p. 727, lines 1-8

<sup>305</sup> The observation that the incremental costs of firm service is unknown follows from the AESO's latest 10 year transmission plan, which was filed as Ex. 107 as an attachment to the response to EnCana.AESO-004(a). On p. 56 of that document, the AESO notes that as long as intertie transactions are for opportunity services, it does not plan and reinforce the transmission system to provide a higher level of service. In addition, the AESO indicated that is not obligated to reinforce the transmission system for potential firm transfers in the absence of the users of the merchant facilities or the merchant developers contracting for firm service.

Another potential concern that the Board has with the proposed MTS rate, based on the exchange referred to above between Board counsel and Mr. Martin, is the potential that MTS contracts will be used by the AESO as a signal or catalyst for transmission system planning and reinforcement. While the following exchange between counsel for Powerex and the AESO panel occurred in the context of the proposed XTS rate, the Board is concerned that these comments also reflect the AESO's approach to contract sign-ups for proposed rate MTS.

Q And is it correct to think that for transmission capacity planning purposes as you look out in the future that if the AESO enters into firm XTS contracts, then the capacity in respect of those contracts -- let's stay with the 200 megawatts for discussion purposes -- will be included in the transmission planning analyses so that you will be in a position to say, Yes, we build and plan our transmission capacity for the purpose of meeting firm export loads?

A MR. MARTIN: Yes, that would be the intent.

And I understand that was also part of the reason stakeholders wanted a firm rate proposed, so that they could start providing, I'll call it, real feedback to the AESO that there was a need for firm capacity that we would then build for.<sup>306</sup>

To the extent that this passage applies to merchant transmission service, it suggests that if a customer contracts for 200 MW of MTS service, the AESO would then begin to include an additional 200 MW above forecasted domestic load in load forecasts used for system planning purposes. Thus, if incremental system costs were to be generated by the consideration of the additional 200 MW of capacity, the Board understands that the incremental deep system costs would be borne by DTS customers.

The Board considers that using XTS or MTS contracts as a signal or catalyst for system planning purposes is not desirable for at least two reasons.

Firstly, noting that the minimum term for Rate MTS is 1 year (as distinct from the five year minimum term for Rate DTS), the Board is concerned that a customer seeking MTS service from or to a merchant intertie could induce additional system capacity to be created, simply by contracting for rate MTS. During cross-examination by Board counsel, both the AESO panel<sup>307</sup> and the TCE panel<sup>308</sup> were asked about the amounts that would be payable to the AESO by customers contracting for service under rate MTS. From these discussions, the Board is concerned that to the extent the AESO initiates the planning and development of additional capacity from or to a merchant intertie on the basis of the capacity of rate MTS contracts, the maximum cost incurred by an AESO customer as a result of entering into a rate MTS contract for a 1 year term could be considerably less than the costs of system reinforcements necessary to assure an essentially firm level of service.<sup>309</sup>

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<sup>306</sup> Tr. Vol. 3 p. 601, lines 9-25 and p. 602, lines 1-2

<sup>307</sup> Tr. Vol. 3 p. 723 lines 10-25 and p. 724

<sup>308</sup> Tr. Vol. 6, p. 1198 lines 10-25 to p. 1204 lines 1-6

<sup>309</sup> TCE indicated in discussions with Board counsel (Tr. Vol. 6, p. 1203) that assuming ATC availability in all hours, the annual cost of a Rate MTS contract would be \$3.405 million. This estimated cost declined in direct proportion to reductions in percentage of hours that ATC was expected to be available in a given year.

Secondly, given that additional system costs incurred to accommodate service over a merchant intertie fall within section 27 of the 2007 *Transmission Regulation*, the Board finds that insufficient evidence was offered in this proceeding to allow the Board to determine whether the proposed MTS rate is in compliance with section 27. Accordingly, the Board is unable to approve this rate at this time.

The Board acknowledges that the TCE witness panel questioned the likelihood of customers entering contracts to induce additional firm capacity to or from an intertie since before an intertie is built, the benefits of firm import or export transactions cannot be used to offset the substantial cost of contracting for firm MTS service.<sup>310</sup> However, the Board is concerned that the potential for customers to contract for firm MTS service to induce or advance additional deep system capacity may nevertheless exist. This potential is of sufficient concern that the Board is not prepared to approve the rate MTS at this time.

### **7.3.1.2 Merchant Opportunity Service Rates (MOS 1 Hour and MOS 1 Month)**

The AESO proposed that its MOS 1 Hour and MOS 1 Month rates would generally reflect the cost allocation principles used by the AESO to develop its proposed XOS 1 Hour and XOS 1 Month rates. The main exception was that the AESO proposed that its MOS rates should not include an allocation of costs related to the existing interties, since the existing intertie facilities would not be used by exporters using a merchant line to access other markets.<sup>311</sup>

For energy either generated or consumed in Alberta, the Board agrees that customers using a newly constructed merchant intertie would not require the use of the existing Alberta-British Columbia or Alberta-Saskatchewan interties. This indicates that the minimum charge component of the rate (based on the incremental variable cost associated with providing the service) would be equal to or lower than the corresponding XOS rate minimum charge. However, the Board finds that no evidence indicated that the value of the proposed merchant opportunity service (MOS) is less than the value of export opportunity service (XOS). Accordingly, the Board finds that the value of service based rate for MOS 1 Hour and MOS 1 Month is \$3.98/MWh and \$4.36/MWh respectively, consistent with the Board's findings in section 7.2.1.

## **8 TERMS AND CONDITIONS OF SERVICE**

### **8.1 Customer Contribution Policy**

#### **8.1.1 Interconnection Project Cost Function**

In Decision 2005-096, the AESO was directed to undertake further research to devise a more comprehensive investment function proposal which avoids the concerns expressed by the Board in that decision and which reflects the design principles described by the Board in that Decision.<sup>312</sup> A proposal based on this research was to be presented in the AESO's 2008 GTA.

In the Application, the AESO noted that following extensive debate during the 2005/2006 GTA, the Board in Decision 2005-096 amended the maximum local investment formula to provide a

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<sup>310</sup> Tr. Vol. 6, pp. 1209-1210

<sup>311</sup> Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13- 19

<sup>312</sup> Decision 2005-96, pp. 57-58 (Direction 13A)

minimum investment allowance of \$2.5 million plus an additional allowance of \$100,000 per MW of project capacity.<sup>313</sup>

As a result of feedback obtained during stakeholder consultations, the AESO undertook to revise the investment allowances under the contribution earlier than the 2008 GTA. It is apparent that the AESO encountered obstacles related to the limited amount of available POD cost data in its efforts to gather the data required to fulfill the Board's direction to develop a cost based interconnection project cost function. The Board wishes to acknowledge the AESO's diligence in complying with the Board's direction. The Board confirms that the AESO has complied with the Board's Direction 13A from Decision 2005-096.

The AESO used the same cost function both to determine a proposed investment function under the customer contribution policy and to design the POD charge component of Rate DTS. Accordingly, to the extent that parties made submissions related to determining a POD cost function for POD charge purposes, such submissions have also been taken into account by the Board, as appropriate, in its assessment of the appropriate POD cost function for customer contribution policy purposes.

As discussed in section 5.7.3 of this Decision, the Board has determined that it is appropriate that the same underlying average cost function be used for both POD charge determination and contribution policy investment allowance purposes.

However, in section 5.7.7 of this Decision, the Board has not approved the POD cost function proposed by the AESO. Accordingly, for greater certainty, the Board confirms that the approved POD cost function set out in section 5.7.7 of this Decision is to be used as the basis for the maximum investment function. The Board discusses the additional steps required to convert the approved POD cost function into the approved maximum investment allowance function.

### **8.1.2 Determination of Maximum Investment Function**

Article 9.6 of the AESO's proposed T&Cs describes the determination of the customer contribution for a load interconnection project. Within Article 9.6, the major determinant of the customer contribution is the maximum local investment (maximum investment). In section 6.5.3 of the Application, the AESO discussed its efforts to comply with Directive 13 of Decision 2005-096.

The AESO considered that Directive 13A required the multiplier of its proposed interconnection project cost function to be consistent with a maximum investment function such that 80% of projects do not pay a contribution. Based on an analysis of sample POD cost data from its analysis of current projects sample, the AESO determined that applying a multiplier of 1.15149 to its proposed interconnection project cost function would result in 24 of 30, or 80%, of projects being fully covered by the resulting maximum investment function.

The AESO noted that the 80/20 criterion established by its predecessor was originally approved by the Board in Decision 2001-6. It further submitted that using this criterion assists in harmonizing the AESO's contribution policies with those of the Discos and helps to preserve the

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<sup>313</sup> Exhibit 007, Section 6.3.2 of the Application

balance between the need of new customers for service and for service without subsidization from existing customers. Additionally, the AESO submitted that the 80/20 criterion supported the principles that most new customers would not see a different cost of system connection than existing customers, and existing customers should not bear any extraordinary costs of system expansion.

In argument, the AESO noted that while its proposed POD cost function had changed from the POD cost function it initially proposed in the Application, its proposed multiplier of 1.15149 did not change as a result of the revisions to the cost function since the multiplier still resulted in 80% the 30 greenfield projects being fully covered by the resulting maximum investment function.

The AESO further noted that its proposed application of the multiplier was not debated by any party during the hearing.

The Board considers that before ruling on the appropriate multiplier to be used to set maximum investment allowances under the customer contribution policy, it is first necessary to address the issue of whether a so called “80/20 Rule” should apply.

#### **8.1.2.1 Application of “80/20 Rule”**

As discussed in section 8.1.1 above, Direction 13A from Decision 2005-096 required the AESO to perform research leading to the development of a function describing the relationship between interconnection project capacity and average cost. Direction 13A also instructed the AESO to perform research into a multiplier of the AESO’s proposed average interconnection cost function that would provide a degree of tolerance above the average interconnection cost function. Consistent with the Board’s finding in section 8.1.1 above that the AESO’s interconnection project cost research complied with the requirements of Direction 13A, the Board considers that the AESO’s research into the development of an appropriate multiplier of the average interconnection project cost has complied with the Board’s direction.

It appears that Direction 13A has been interpreted by the AESO and some other parties as a general endorsement for the continuation of a so-called “80/20 Rule” previously applied to the AESO’s predecessor.<sup>314</sup>

However, the direction to devise a multiplier such that 80% of projects of the project fall under the resulting maximum investment function represented no more than a direction to conduct a one-time study. The mention of 80% in the direction should not have been interpreted as a general endorsement of an 80/20 rule as a guiding principle, nor did it require that the 80% threshold be used by the Board in determining an appropriate multiplier for the maximum investment function for the 2007 tariff.

The underlying principles intended to govern the design of AESO and utility contribution policies generally were discussed in some detail in sections 6.1.1 and 6.1.4 of Decision 2005-096. Included in the most important considerations set out in that decision are the following:

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<sup>314</sup> See Ex. 007, p. 18; Ex. 015, p. 26; AESO Argument, p. 43, p. 44, p. 79, p. 81, AESO Reply, p. 34; DUC Evidence (Ex. 229, p. 30); TCE Reply Argument, p. 11

- the underlying purpose of the contribution policy is to send economic signals to AESO customers when considering alternatives for siting their interconnecting loads;<sup>315</sup>
- an excessive investment allowance could provide incentives for customers to pursue higher standards of interconnection facilities than required and justify doing so on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance;<sup>316</sup>
- because the incremental revenue approach may place undue upward pressure on rates, maximum investment allowances should be at a level below a level representing the incremental revenues expected to arise from the interconnection of a new customer;<sup>317</sup>
- investment allowances should be set with regard to the anticipated costs of establishing an interconnection reflecting acceptable standards of functionality and service established by the AESO;<sup>318</sup>
- interconnection facility service characteristics and standards of functionality may change over time.<sup>319</sup>

These considerations can not be assumed to be automatically addressed solely by applying an 80/20 rule test to a proposed maximum investment function.

The Board considers the following passage from Decision 2005-096 to be instructive:

The Board considers that the underlying rationale for the consideration of revenues in the context of a contribution investment policy relates to the manner in which a new customer interconnection may benefit existing customers through a broader sharing of embedded system costs. In this context, the incremental transmission revenue generated by connecting the new customer is also the maximum level of the “willingness to pay” of existing customers. Furthermore, since the Board considers that a new customer may normally be presumed to be seeking an interconnection in order to obtain the benefits of electrical service rather than an investment allowance per se, the Board considers that the new customer should be provided the incentive to commit an investment as long as the costs of any required interconnection facilities are offset. Thus, there is the potential risk of creating a substantial difference between the respective willingness to pay of the new customers and that of existing customers. The difficulty in creating a utility investment policy is to determine how to design a maximum investment allowance function that will fall at a reasonable level within this range.<sup>320</sup>

The key concept described in the above passage is that the level of investment allowance should be targeted to fall somewhere in a *range* between the bookends of: (1) making the connecting customers pay for the full cost of a new interconnection and (2) providing a full contribution credit to reflect the benefit of embedded system cost sharing new AESO customer can provide to existing customers.

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<sup>315</sup> Decision 2005-096, p. 43

<sup>316</sup> Decision 2005-096, p. 44

<sup>317</sup> Decision 2005-096, p. 44

<sup>318</sup> Decision 2005-096, p. 44

<sup>319</sup> Decision 2005-096, p. 44

<sup>320</sup> Decision 2005-096, p. 56

Setting the appropriate level for the maximum investment allowance is a balancing act. On one hand, it is desirable that the level of required customer contributions not dissuade customers from connecting to the system. On the other hand, the level of the investment allowance offered should ideally not be higher than most customers need to be incented to connect. However, as a result of additional considerations presented during the proceeding, the Board is no longer persuaded that, in and of itself, an 80/20 rule achieves the proper balance.

One piece of new information arises from section 6.5.3<sup>321</sup> of the Application regarding the way in which customer contribution levels have changed over time. This section highlighted the differences between the required customer contribution level for similar projects under contribution policies in effect in the years between 1999 and 2005 as compared to the contribution level required under the contribution policy approved in Decision 2005-096.

If the message that was intended to be conveyed in section 6.5.3 of the Application was that the level of the maximum investment allowance should be raised (because the contribution policy approved in Decision 2005-096 required significantly higher customer contributions than did previously approved contribution policies), the Board does not agree with this conclusion. The interconnection project queue appears to have grown rather than declined under the contribution policy prescribed in Decision 2005-096.<sup>322</sup> The Board finds this to be clear evidence that having a maximum investment allowance which provided that more than 20% of interconnection projects must pay some contribution has not dissuaded AESO customers from proposing a greater number of new interconnections than can be immediately accommodated by the AESO and the TFOs. The Board therefore concludes that the lower investment allowance permitted in Decision 2005-096 did not discourage investment.

Another significant concern that the Board has with an 80/20 rule is that the application of such an 80/20 rule may become circular or self fulfilling, in that higher cost projects may trigger increases in the multiplier. As a result, the Board is concerned that to perpetuate an 80/20 rule may undermine the principle that the level of the maximum investment function provides an economic signal to AESO customers. For example, in Decision 2005-096 the Board expressed a similar concern in the context of its proposed pre-paid O&M charge:

The Board is particularly concerned that, in applying the proposed DTS customer pre-paid O&M charge only to the deemed “optional facility costs” of a new interconnection, the AESO appears to be implicitly assuming that the combined amount of the pre-paid O&M costs associated with the “non-optional” local interconnection facilities and the cost of the non-optional facilities themselves will fall below the level permitted under the maximum investment allowance. However, the Board considers that this should not be presumed, particularly in light of the adjustments to the maximum investment function ordered by the Board in Section 6.1.4 above.<sup>323</sup>

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<sup>321</sup> Ex. 007, pp. 28-29

<sup>322</sup> The AESO’s response to undertaking 7 (Ex. H-023, p. 3 of 5) indicates that the load interconnection project queue had grown to 69 projects as May 18, 2007, which exceeds the total number of projects (59) reported in Attachment BR.AESO-016 (Ex. 092) over the period 1999-2005.

<sup>323</sup> Decision 2005-096, pp 68-69

The AESO discussed the Board's concern in that context:

The Board noted above that it was inappropriate for the AESO to presume that the combination of standard facility costs and the O&M charge would be covered by the investment level. The AESO acknowledges the Board's position but suggests that such a principle only applies if the customer contribution policy has a set investment level. If the investment level was set at a specific value and was not based upon the number of projects that are not required to pay a contribution – which is not how the current and proposed investment policies are structured (i.e. 80% of projects are not to pay a contribution per Board Directive 13A in Decision 2005-056, and further described below) – the number of customers that would be required to pay a contribution would increase. But as noted the investment level is required to meet the criterion that 80% of projects do not pay a contribution. If the O&M charge was to continue to be applied to standard facilities, the cost function would increase but so would the investment level function so as to maintain the target of 80% of projects not having to pay a customer contribution. As such, the AESO is of the view that the benefit to economic siting and facility development originally intended by the Board by including the O&M charge is very limited.(Emphasis added).<sup>324</sup>

The Board considers that the concern discussed by the AESO in the emphasized portion of the passage above applies to all interconnection project costs. That is, if increasing interconnection project costs are, in the normal course, constantly updated within the maximum investment allowance to reflect an 80/20 rule, the ability of the maximum investment function to provide an economic signal may be significantly diminished over time.

Accordingly, while the Board has assessed how the 80% of projects threshold specified in Directive 13A impacts the multiplier and resulting maximum investment allowance, for the reasons discussed above, the Board's statements in Decision 2005-096 do not constitute an endorsement by the Board of an 80/20 rule. Rather, the Board's statements in that decision were intended simply to direct the AESO to conduct a study to determine a multiplier. A determination would then be made on whether or not use of that multiplier was warranted.

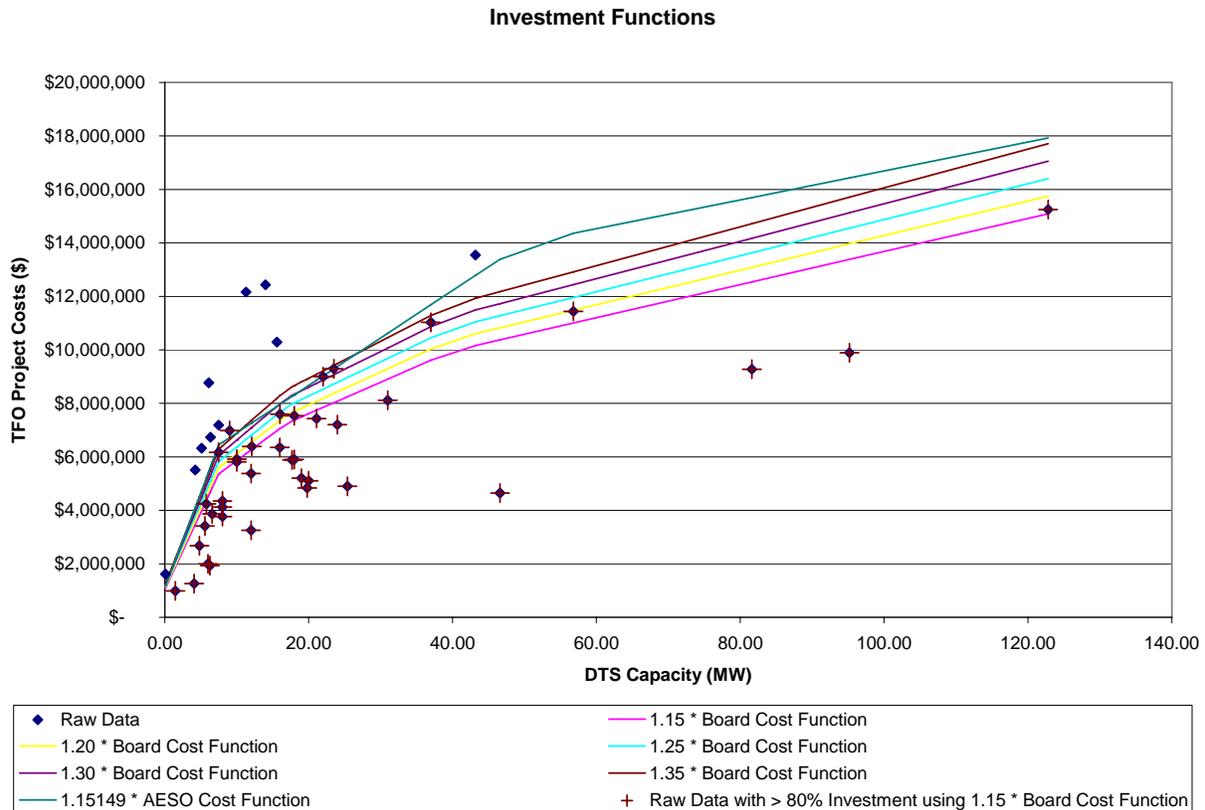
The Board provides its analysis and findings on the determination of an appropriate 2007 tariff investment function multiplier in the immediately following section.

### **8.1.2.2 Appropriate Multiplier for 2007 Tariff Maximum Investment Function**

In determining the appropriate multiplier to apply to the approved POD cost function, the Board evaluated a rounded off version of the AESO proposed multiplier of 1.15149, namely 1.15, and developed cost functions in 0.05 multiplier increments until such time as 80% of the 48 point dataset projects would receive full investment. 80% of the 48 point TFO project cost data points received full investment using a multiplier of 1.35 applied to the Board approved cost function. A graph of the investment functions based on this data, including the AESO's final proposed investment function, is shown below:

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<sup>324</sup> Ex. 007, p. 14 of 47



In determining the impact that outlying data points have on the level of the multiplier required to satisfy an 80/20 rule, the Board analyzed the 48 point dataset to determine how many data points would receive at least 80% investment using the rounded version (1.15) of the AESO’s proposed multiplier of 1.15149.

A multiplier of 1.15 results in 27 data points receiving full investment, six data points receiving over 90% investment, and another five data points receiving at least 80% investment. As such, 38 out of 48 data points, or 79.2% of the data points receive at least 80% investment and the majority of these points receive full investment.

The above graph shows the raw data points that received at least 80% investment using the Board approved cost function and a 1.15 multiplier to determine the maximum investment function. These data points are marked with a + sign and noted in the graph legend.

The Board considers that using a 1.15 multiplier is more than adequate in providing a sufficient investment level of investment based on the 48 point sample dataset. This multiplier works just as well if a 30 point “greenfield” subset of the 48 point dataset is considered. Further, the 1.15 multiplier was also proposed by the AESO even after it modified its cost function in argument.

As the AESO obtains new TFO project cost information in the future, the 48 point dataset may be expanded and cost functions further analyzed. The key though is that any future changes to the investment function be based on actual project costs, without the potential circular bias that implementing and maintaining an 80/20 rule may impose. The Board observes that the 1.15 multiplier, when applied to the Board approved cost function, achieves a result that is not substantially different than the result that would be produced by application of an 80/20 rule. To

be clear, an 80/20 rule is not to be relied on in future when amending the maximum investment policy.

For all of the above reasons, the Board approves a multiplier of 1.15 to be applied to the cost function approved in section 5.7.7 of this Decision to determine the maximum investment function.

The resulting Board approved maximum investment function is as follows:

$$Y = \$1.028 \text{ million} + \$0.578 \text{ million/MW for the first 7.5MW} + \\ \$0.200 \text{ million/MW for the next 9.5MW} + \\ \$0.118 \text{ million/MW for the next 23MW} + \\ \$0.062 \text{ million/MW for all MW above 40.0MW}$$

The cost function approved in section 5.7.7 of this Decision entails rounding such that a pure application of the 1.15 multiplier may result in a difference in the third decimal in the above function. The function above has been determined by multiplying the unrounded Board approved cost function by 1.15, and then round the values to three decimals, and is the function to be implemented by the AESO.

### 8.1.3 Inflation Adjustments to Maximum Investment Function

TCE argued that although the AESO witness panel had confirmed that the investment levels set out in Article 9.6 were designed so that about 20% of DTS customers who attach to the system will make a contribution,<sup>325</sup> it also confirmed that as the costs of projects rises overtime, on average more than 20% of customers would be required to make a contribution.<sup>326</sup> In recognition of the effect of inflation, TCE submitted that the Board should direct the AESO to amend Article 9.6 of the T&Cs to include a project inflation factor such as the Consumer Price Index (CPI) or another widely recognized factor.

With respect to TCE's proposal, the AESO noted that while it had agreed that a project inflation factor could be considered if an appropriate index could be used, the contribution policy in place at a given time should provide a price signal that reflects the current economic situation. The AESO submitted that the contribution policy should not be static, but should rather be revisited as more data becomes available.

DUC argued that the maximum investment allowance levels provided under the AESO's contribution policy should be increased by 5% to reflect inflation over the period of late 2007, 2008, and 2009 that the AESO's 2007 tariff may be in effect.

The AESO replied that the 5% increase proposed by DUC did not appear to be based on any trending analysis or inflationary economic reporting. The AESO further noted that an inflation rate based on Alberta CPI approved by the Board in other decisions was used to update POD cost data within the customer contribution study provided as Appendix F to the Application.<sup>327</sup>

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<sup>325</sup> Tr. Vol. 2, p. 501, referenced at p. 64 of TCE Argument

<sup>326</sup> Tr. Vol. 2, p. 502, referenced at p. 64 of TCE Argument

<sup>327</sup> Ex. 015, referenced at p. 34 of AESO Reply

As discussed in section 8.1.2.1 above, the Board has not endorsed the so-called 80/20 rule. Accordingly, the Board rejects TCE's proposition that that Article 9.6 should be amended to include an inflation allowance to maintain adherence to an 80/20 criterion.

The Board agrees with the AESO that DUC's proposal for a 5% inflation adjustment is not necessary in light of consideration of the inflation adjustments applied to POD cost data as part of the AESO's customer contribution study. The Board considers that as the average POD cost function adopted by the Board in this Decision already reflects inflation adjusted POD cost data, no further adjustments are necessary to bring the data up to date. The Board also agrees with the AESO that little basis was provided by DUC to support the selection of 5% as an appropriate inflation adjustment.

The Board disagrees with DUC's view that an additional inflation adjustment is necessary to reflect the anticipated continuation of the 2007 AESO tariff into 2008 and 2009. The maximum investment function set out in section 8.1.2.2 of this Decision is significantly above the maximum investment allowance set out in Decision 2005-096. The Board considers that the increase in the level of the maximum investment allowances, particularly for AESO customers with a large contract capacity, offsets the impact of inflation on the cost of new interconnections.

The Board agrees with the AESO that that the effects of inflation on POD costs may be relevant to the reconsideration of maximum investment levels in the future. Such consideration should occur, if necessary, in the context of a future GTA.

#### **8.1.4 Applicable Tariff for Customer Contributions and Contract Capacity Increases**

In section 6.5.1 of the Application, the AESO described its proposed changes to Articles 9.2, 9.7, and 9.9 of its T&Cs. The AESO noted that its practice has been to recalculate the customer contribution for an interconnection project on the basis of the tariff in effect at the time the original interconnection was constructed.

The AESO submitted that it was appropriate to revise the amounts of customer contributions based on the contribution policy in effect at the time of the original system access request because the events described in Article 9.9 and the sharing of facilities discussed in Article 9.10 of the T&Cs are largely outside the control of the customer and primarily affect the original facilities built to accommodate the original system access request. However, the AESO acknowledged that it had also encountered situations where a customer request for an increase in contract capacity required the construction of new transmission facilities to accommodate the contract capacity increase. The AESO noted that this situation was not currently explicitly addressed in the T&Cs, but that it was the AESO's business practice to apply the approved tariff in effect at the time of project commitment to determine the customer contribution and contract term. In light of this practice, the AESO proposed updates to Article 9.2, 9.7, and 9.9 to reflect this treatment.

No parties took issue in argument or reply with these changes as proposed by the AESO. The Board has reviewed Article 9.2, Article 9.7 and Article 9.9 and approves these provisions as filed.

## 8.2 AESO Standard Facilities

### 8.2.1 Matters Raised in Evidence of ATCO Electric

In its evidence,<sup>328</sup> AE expressed a concern about the AESO's interpretation of "standard facilities" in the context of the application of the AESO's customer contribution policy. AE noted that in Decision 2001-6, the Board had stated that the total Alberta electric system should be planned with the appropriate mix of transmission and distribution facilities and that the contribution policies of various entities should work together so as not to disturb proper planning. AE also noted that Decision 2005-096 indicated that the primary focus of efforts to harmonize customer contribution policy matters between Discos and the AESO should be on harmonizing the definitions of "standard facilities" and "optional facilities."

AE indicated that it had expressed concern in discussions with the AESO regarding the commercial treatment of certain projects. AE submitted that the best way to uphold a principle that the AESO and Disco contribution policies not disturb proper planning is to ensure that the commercial determination of standard facilities supports the best overall planning solution. To illustrate its concerns, AE provided two examples of projects<sup>329</sup> in which it considered that the AESO's commercial determination of standard facilities had frustrated proper planning efforts.

AE submitted that as regulated entity it can and will take into account the greater public interest when making decisions regarding the evolution of the electric system (including consideration of the cost of losses, reliability, power quality, motor starting capability, and voltage support). However, AE submitted that as customers making decisions about transmission connection and distribution connection would not take such matters into account, the AESO's definition of standard facilities must take into account the optimal solution for the integrated electric system, and not simply the solution that minimizes the currently forecast transmission costs.

The AESO submitted a supplemental filing to the Application on May 1, 2007<sup>330</sup> which, among other things, proposed revisions to Article 9.1 of the T&Cs (added words underlined):

In considering requests to provide service to a new POC, or to increase the capacity of or improve the service to an existing POC, the AESO will determine the appropriate means of delivering the requested service.

- (a) If the Customer's request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension ("the project")
- (b) If the AESO determines that the viable and most economic option for providing service to a Customer includes a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then:
  - (i) for the purposes of determining the Local Investment in Articles 9.3 to 9.6, the project costs referenced in Article 9.3 will include only the costs of the transmission facilities required in the most economic service option (if any);
  - (ii) and if the customer selects a transmission facility instead of the one determined by the AESO to be viable and the most economic, then the

<sup>328</sup> Ex 223

<sup>329</sup> Ex 223, pp. 3-11 (Updike 144 kV line and substation, and a potential connection of two oilsands developments)

<sup>330</sup> Ex. 349

customer will pay the cost of the transmission facility less the Local Investment as calculated in accordance with part (i) above.

In its rebuttal evidence,<sup>331</sup> the AESO noted that it was engaged in ongoing discussions with its customers (including AE) regarding its interpretation of AESO standard facilities as part of its compliance with the Board's harmonization direction from Decision 2005-096.<sup>332</sup> It also presented a revised proposal regarding the Updike project that had been raised by AE.

Given the AESO's rebuttal evidence, AE indicated in argument that it and the AESO were able to reach a mutually acceptable commercial solution on the most pressing matter that AE had raised, and made considerable progress on the other matter. As such, AE stated that, the Board's intervention was not required to appropriately address the matters raised in its evidence. However, AE requested that the Board consider confirming in its Decision that while the AESO should be afforded discretion in determining of what constitutes AESO standard facilities in specific instances, the AESO should apply its investment policy in a manner that ensures that the most appropriate facilities are built. AE submitted that the determination of the most appropriate facilities should uphold the principles of good transmission and distribution practice and should give due consideration to all aspects of electric system planning (including reliability, power quality, protection, distribution and transmission losses, maintenance practices, and operating criteria and standards).

It remained AE's view that certain additional language (described in its response to BR.AE-003)<sup>333</sup> should be inserted into the definition of AESO standard facilities and into Article 9.13 of the AESO T&Cs. In reply argument, the AESO indicated that it would not take issue with AE's proposed changes to the AESO standard facilities definition and Article 9.13, if so directed by the Board.

In reply, IPPCA expressed concern that the AESO and AE appeared to have agreed that a larger transmission capital investment should be made to avoid losses on the distribution system, yet the higher transmission capital expenditures made no mention of a higher contribution by the Disco. IPPCA also expressed concern with the characterization of the issue as a commercial matter between parties. IPPCA submitted that the apparent understanding between the AESO and AE had the potential to cause significant transmission investment to offset distribution losses. As it did not appear that reduced losses would receive the same consideration with respect to sites of transmission connected industrial customers, IPCAA submitted that the AESO's proposed arrangement would not provide equitable treatment between transmission connected and distribution connected loads.

Both the AESO and AE proposed certain changes to the AESO tariff T&Cs to address AESO standard facilities issues raised in AE's evidence. The core proposition in AE's evidence is that customer contributions arising from the determination of AESO standard facilities can, in some instances, disrupt optimal planning processes by influencing the mix of transmission and distribution facilities built for specific projects. The Board does not agree.

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<sup>331</sup> Ex. 347

<sup>332</sup> Decision 2005-096, p. 73

<sup>333</sup> Ex. 292

The Board considers it important to look at the circumstances of both a direct-connect customer and a Disco that is deciding how to provide service to a new end-use customer or to accommodate load growth within its service territory. There is generally no need for a Disco to consult with the AESO when one of its prospective or existing end-use customers requires new or expanded interconnection facilities, unless and until the Disco determines that some additional DTS contract capacity and associated transmission facilities may be required to accommodate the requirements of the Disco's end-use customer or growth within the Disco's system. It is only at this point that the AESO becomes involved in assessing the requirements of the end-use customer (with the advice and assistance of the Disco) to determine the appropriate amount or increment of DTS capacity that the Disco would be required to contract for in respect of a new or expanded AESO POD. If it is subsequently determined that additional transmission facilities will be required, the Board understands that the Disco and the AESO collaborate to prepare an application pursuant to section 34 of the EUA. Pursuant to section 34 of the EUA, that application is prepared and submitted by the AESO.

In its response to AE.AESO-003, the AESO provided hyperlinks to eight separate process guidelines related to distribution point of delivery interconnection process guidelines.<sup>334</sup> These documents were prepared by the AESO with assistance from Alberta Discos and TFOs.<sup>335</sup> Furthermore, while the Board will not comment on the specific content of the documents, for the purposes of this proceeding, it is apparent that they are comprehensive and detailed and that they were prepared for the express purpose of determining the appropriate set of facilities to be used in the circumstances contemplated.<sup>336</sup>

The following two paragraphs appear in each of the eight guidelines:

This guideline is intended solely for the purpose of supporting the AESO's customer interconnection process to arrive at proposed interconnection concepts that are optimized on a technical and economic basis. It will not in any way address or determine the AESO's facility cost allocation between system and customer, nor will it be used in any way as a guideline in applying the AESO approved tariffs and investment policy.

This guideline is intended to facilitate documentation of the project need and the evaluation done to support the need, in alignment with the interconnection process. The interconnection process has a requirement for AESO endorsement and AEUB approval of the project need.<sup>337</sup> (Emphasis added)

The above paragraphs reflect that the decision making process respecting new POD interconnections is focused on achieving an optimal technical and economic solution, and that these considerations are to ultimately be reflected in need applications. Given this, the Board considers there is no basis on which to expect that the transmission facilities built following the approval of a section 34 application would not reflect the optimal combination of transmission and distribution facilities required to serve the end-use customer of the distribution system owner. Accordingly, it is not apparent to the Board that an AESO tariff proceeding is the appropriate forum in which to address the concerns identified in AE's evidence.

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<sup>334</sup> Ex. 098

<sup>335</sup> Ex. 098, AESO.AE-3, pp. 2-3, Tr 847

<sup>336</sup> Ex. H-002, p. 1

<sup>337</sup> Ex. H-002, p. 1

Nevertheless, within the context of the AESO's tariff, the Board considers that an important principle is that Discos and AESO direct connect customers be afforded comparable treatment under the AESO's customer contribution policy. Comparable treatment will generally be achieved if the cost of AESO standard facilities is determined in a manner that reflects the capacity of the actual transmission facilities built in accordance with the section 34 application (approved by the Board) and in a manner that is consistent, as between Discos and direct connect customers. Therefore, the Board considers that, all other things being equal, the general principle should be whether a DTS contract capacity increase is requested by direct connect customer of the AESO or by a Disco, the resulting facilities determined to be needed should be the same, reflecting the one line, one transformer AESO standard facilities definition. Given the Board's affirmation of comparable treatment of direct connect customers and Discos, the concern raised by IPCAA regarding possible inequitable treatment as between transmission connected and distribution connected loads does not arise.

The Board considers that to the extent that AE's issues are tariff related, the appropriate forum in which to address these concerns are in the Disco tariff proceedings, and not in the AESO's tariff proceeding. The extent of the Disco's ability to pass through optional facility costs (as determined by the AESO applying its tariff) depends on the Disco's tariff and the contribution policy contained in that tariff. Thus, the Disco remains responsible for ensuring the reasonableness of all of its revenue requirement components. As such, the Disco may bear some risk that the full amount of a customer contribution assessed by the AESO may not be fully recoverable through the Disco's tariff. This may for example arise if the Disco for some reason has not acted reasonably, such as by having requested AESO optional facilities on behalf of its end-use customer in the context of the section 34 application process, but then is subsequently unable to pass on to its customer the full amount of the costs of the facilities that exceed AESO standard facilities, for example if its own contribution and investment policies do not permit such costs to be passed on to its customer and the Board denies any proposed inclusion in the Disco's revenue requirement.

For the purpose of this Decision, as long as a Disco has complied with the AESO's interconnection guidelines, its own tariff, and has acted reasonably and prudently incurred the costs, the Board considers that there would be only minimal risk to the Disco of disallowance of contributions paid to the AESO. However, such risk on the Disco may arise if the Disco pursues transmission facilities inconsistent with the interconnection process guidelines either on its own initiative or at the request of its end-use customer. The reasonableness of Disco expenses is, of course, assessed in Disco tariff proceedings.

In light of these findings, the Board approves the AESO's standard facilities definition and related T&Cs as initially proposed by the AESO in the Application but *not* the amendments subsequently proposed by the AESO in its supplemental filing.<sup>338</sup> Furthermore, as the issues raised by AE in the current proceeding relate to EUA section 34 processes and not tariff matters, the Board is not prepared to comment on any arrangement or accommodation that may or may not have been reached between the AESO and AE in respect of issues raised by AE in this proceeding.

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<sup>338</sup> Ex. 349

### 8.2.2 Transmission vs. Distribution Service and Required Use of Variable Frequency Drives

The PPGA expressed concern about the process followed by the AESO to determine whether “standard facilities” should encompass a transmission or a distribution connection.<sup>339</sup> The PPGA considered the process to be unclear and unsystematic, and submitted that the Board should direct the AESO to clarify this process. The PPGA submitted that the AESO should standardize the flicker limit test used to determine “standard facilities” to be based upon 3 times in-rush, or a typical soft-start mechanism – as opposed to a VFD (unless the customer agrees to install a VFD). The PPGA considered that this would ensure that the test is fair and that customers are not directed to implement an AESO initiated VFD to accommodate motor starting.

The AESO argued that although it maintains a clear policy on flicker limits for the transmission system, flicker limits on the distribution system are set not by the AESO, but by the Discos, based on industry standards. The AESO submitted that the flicker limit standards of the Discos have been in place for some time, and have not changed in recent years. In its rebuttal evidence, the AESO stated that in some circumstances, local conditions on a distribution feeder may cause the Disco to apply more stringent measures. The AESO submitted that to direct either the AESO or Discos to follow any other methodology regarding flicker limits would be contrary to good industry practice.<sup>340</sup>

The AESO also pointed out that the determination of standard facilities is used to assist the AESO with decisions on customer contribution levels; it does not limit the customer’s selection of a transmission or distribution option.

The AESO’s Distribution Point-of-Delivery Interconnection Process Guideline: Evaluation of Transmission versus Distribution Alternatives for Large Customers states that the Disco will ensure that the voltage fluctuation associated with motor starting by one customer does not create problems for other customers. This guideline states that voltage fluctuation during motor starting is not to exceed the Disco’s standards for fluctuation as specified in the AESO Interconnection Process Guide, Standards of Service. To determine the significance of an impact the motor starting will have on the distribution system, the Disco models the typical characteristics of the motor to determine what limit on inrush current is necessary to limit the voltage fluctuation to the Disco’s standard. The guideline goes on to state that when the voltage fluctuation is greater than the Disco’s standard, voltage reduction and inrush current limiting techniques are evaluated *such as* the use of an autotransformer or a VFD.

If voltage reduction techniques do not appear promising, then distribution system improvements are to be evaluated. In lieu of installing motor starting aids, certain alternatives are to be investigated. This guideline recognizes that each Disco has different voltage fluctuation guidelines.<sup>341</sup>

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<sup>339</sup> Ex. 240, PPGA Transmission vs. Distribution evidence

<sup>340</sup> AESO Reply Argument, pp. 35-36; Ex. 347 AESO Rebuttal Evidence pp. 11-15

<sup>341</sup> Ex. H-002, AESO Distribution Point-of-Delivery Interconnection Process Guideline: Evaluation of Transmission versus Distribution Alternatives for Large Customers, Revision 0: Wednesday March 23, 2005, page 1, section 2.2.1 (“Motor Starting Study”), pages 4-5

The Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service simply summarize the standards that each Disco applies to its distribution system with respect to the allowable voltage fluctuations/flicker.<sup>342</sup> The Board notes that the standards applied by the Discos are not uniformly consistent.

The Board understands that both of these guidelines were developed by the AESO with the involvement of Discos.<sup>343</sup>

No evidence was submitted in this proceeding of an AESO requirement that a VFD would be required to accommodate motor starting on the distribution system. Based on the evidence in this proceeding, the Board agrees with the AESO, that flicker limits on the distribution system are within the purview of the Discos. The Board considers that the decision to provide transmission or distribution facilities in the circumstances of specific customers must be evaluated separately for customers of the AESO and customers of Discos. Accordingly, the Board will not direct the AESO to amend the interconnection process guidelines. In general, to the extent that PPGA, any specific member thereof, or an end use customer of a Disco, has concerns with technical standards established by a Disco, those concerns should be addressed directly with the Disco and if any irresolvable concerns remain they may be pursued in a relevant Board proceeding relating to the relevant Disco.

### 8.3 Prepaid O&M Charge

In the Application, the AESO described its proposed changes to Article 9.4 of its T&Cs.<sup>344</sup> The AESO noted that although the Board had determined in Decision 2005-096 that a charge based on 12% of the cost of the both standard and optional facilities for a customer interconnection, the AESO proposed to amend the prepaid O&M charge to reflect only the cost of any optional facilities built for a new customer interconnection.

The AESO noted that a proposal in the AESO's prior GTA to apply a prepaid O&M charge only on the optional portion of an interconnection project was rejected by the Board in Decision 2005-096. However, the AESO suggested that the Board's prior decision should be reconsidered because the Board's rationale for varying the AESO's original proposal in Decision 2005-096 did not take into account the impact of the ongoing re-assessment of the maximum investment function caused by applying the "80/20" rule.<sup>345</sup>

The AESO also expressed concerns that applying a prepaid O&M charge on standard facilities would require new procedures and processes to ensure O&M costs are being recovered correctly and are not recovered in other components of the TFOs revenue requirement. In addition, the AESO expressed concerns that applying a prepaid O&M charge to standard facilities could compromise harmonization efforts between the AESO and the Discos, since Discos include an O&M charge only on optional facilities. The AESO also submitted that its proposal would be beneficial because it would avoid intergenerational inequity, reduce tariff complexity and would

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<sup>342</sup> Ex. 098, AESO.AE-3, AESO Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service, section 4.3, pages 37-39

<sup>343</sup> Ex. 098, AESO.AE-3, pages 2-3 of 4; Tr 847

<sup>344</sup> Ex. 007, Application Section 6.5.2, pp. 13-15

<sup>345</sup> Ex. 007, p. 14 of 47

respond to the concerns of stakeholders who had opposed the charge during stakeholder consultations.

The AESO argued that applying an O&M charge for facilities in excess of standard would send an appropriate price signal to customers that their postage stamp rate reflects only costs associated with the standard level of service provided by the AESO. The AESO noted that because O&M costs associated with standard service are properly recovered through average rates, it is not necessary to include an O&M amount as part of the customer related cost of standard facilities used to determine the contribution.

TCE indicated in its argument that it was in agreement with the AESO's proposed treatment of prepaid O&M.

The Board reiterates that it considers that it is appropriate to send economic signals to AESO customers that appropriately reflect the cost causation consequences of a customer's decisions.

No evidence was filed indicating that additions of new customer PODs or expansions to existing PODs do not generate some level of incremental TFO O&M costs above and beyond the incremental capital costs of new interconnection facilities. In the absence of such evidence, the Board considers that projected incremental TFO O&M costs should be reflected in the AESO's customer contribution policy.

While the Board agrees with the AESO that a signal reflecting incremental TFO O&M costs should be provided to customers seeking new or expanded interconnections, the Board does not agree with the AESO's proposal to provide this signal only in respect of the "optional" portion of an interconnection project. To the extent that the incremental capital costs of a new interconnection are at least proportionally related to incremental TFO O&M costs, it would be inappropriate to effectively confine this relationship to the optional portion of facility capital costs. If TFO O&M costs are related to facility capital costs, it does not follow that an estimate of incremental TFO O&M costs for the purpose of the economic signal should be generated only by the optional component of capital cost.

It also follows that at the time an estimate of the incremental TFO O&M costs is provided, any amount of the incremental TFO O&M costs deemed to be related to the optional portion of the new interconnections should be borne entirely by the interconnecting customer. This is the effect of Article 9.4 as currently approved. Furthermore, the Board considers that the estimated increment of TFO O&M cost related to constructing standard facilities should be evaluated against the maximum investment allowance established by the Board. Again, this treatment is accommodated in the currently approved wording of Article 9.4. As discussed in section 8.1.2.2, the maximum investment allowances approved in this Decision are larger than those approved in Decision 2005-096.

Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO's 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO's advancement of the cost study used in support of the AESO's revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, \$0.12 of incremental TFO O&M costs will be generated by each \$1.00 of capital investment in an interconnection facility. However, additional research into

the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA.

In light of the above, the Board finds that the wording of Article 9.4 as approved in Order U2005-464 remains for the most part appropriate. However, to avoid potential confusion arising from the use of the word “prepaid”, the Board directs the AESO to amend Article 9.4 as indicated below, and to include this revised wording for Article 9.4 in updated T&Cs to be provided with the AESO’s refile application:

#### 9.4 Operations and Maintenance

For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of:

- (a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and
- (b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

### 8.4 Staged Contracts and Payments of Related Contributions

In the Application the AESO proposed to amend section 9.7 of the T&C to provide that when a customer requests an increase in contract capacity which requires the construction of new transmission facilities, the approved tariff at the time of project commitment for the new contract capacity request is to be used to determine the customer contribution and contract term. The AESO submitted that these constitute new commercial decisions which therefore required a new commercial arrangement. It considered that in such circumstances, the customer contribution calculation in the tariff in place at the time of the request for additional capacity should be applied. While parties did not question this proposed amendment, they did question the AESO’s policy of collecting a customer contribution at the signing of the original request for service for all future staged loads.

In argument TCE stated that the AESO currently requires a generator to pay the entire cost of the customer contribution for an interconnection close to when a request is initially made and sometimes well ahead of when the costs are actually incurred.<sup>346</sup> TCE argued that this may discourage construction of additional generation in Alberta. TCE noted that when questioned by the Board about the need to receive a full customer contribution, where millions of dollars can be required years in advance, the AESO provided what appeared to be two reasons: financial security<sup>347</sup> and a demonstration of commitment.<sup>348</sup> TCE believed that each of these concerns could easily be dealt with through financial assurances and appropriate agreements. Alternatively, TCE submitted that contributions should be placed in an account (incurring interest) and drawn down as the project proceeds.

EPCOR argued that staged contribution payments will provide a sharper and more precise economic signal. It argued that this would conform to one of the purposes of the EUA, which is

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<sup>346</sup> Tr. Vol. 2, p. 348, line 18 to p. 349, line 2, p. 360, line 20 to p. 367, line 1

<sup>347</sup> Tr. Vol. 4, p. 861, line 13

<sup>348</sup> Tr. Vol. 4, p. 864, lines 2-9

to “continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces.”<sup>349</sup>

EPCOR maintained that imposing a tariff requirement that all potential interconnection costs must be paid upfront creates an unnecessary drain on scarce capital during the development phase of a new unit. There was no compelling reason for the AESO to increase capital demands on generators in a competitive industry in a manner which loosens, rather than tightens, the link between the principles of cost causation and fair cost recovery. EPCOR submitted that Article 9 would be enhanced by allowing contribution payments to match actual expenditures where economically efficient to do so, provided that the AESO may require reasonable financial assurances to backstop any expenditure it is called upon to make. These assurances would be in the nature of letters of credit or the credit rating of the requesting customer or any other agreed upon financial assurances.

EPCOR submitted that subsection 29(3)(e) of the 2007 *Transmission Regulation* dealt with the fixed charges for transmission system upgrades, not local interconnection costs, which are dealt with under section 28 of the 2007 *Transmission Regulation*. EPCOR proposed that if the generator does not require a stand alone local interconnection facility (for example switch gear) for a period of several years, payment should be delayed until the actual commencement of construction of this particular local interconnection facility.

EnCana recommended that the Board direct the AESO to discharge the contribution policy in a manner that fosters the lowest cost development of the transmission system.

EnCana suggested that the AESO’s approach is problematic and does not foster the lowest cost development of the transmission system. It pointed out that a customer that makes the cash payment is not compelled to proceed with a second or subsequent stage of expansion and therefore there is no guarantee that the staged costs will be required or incurred. Even if the customer had made a cash payment for the full construction, the cash payment does not encourage a customer’s commitment to subsequent stages because any such payment is fully refundable if the facility costs are not incurred.<sup>350</sup> In the meantime, the customer has lost the opportunity to use the funds in an otherwise productive fashion.

The AESO argued, as it had previously stated,<sup>351</sup> that it is often more economic to construct all the interconnection facilities required to accommodate all the contracted capacity increases at once, rather than over a period of time. If it was determined to be economically beneficial to build all the facilities to accommodate all present and future contracted capacity at once, the customer contribution for the entire project would be collected prior to construction. The AESO maintained collecting all customer contributions at the time of the initial contract is consistent with historical practices that date back to the tariffs of the AESO’s predecessors. It also considered that the current practice maintains harmonization with Disco tariffs and ensures customers - whether they are receiving service from the Disco or the AESO - are being treated equitably.

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<sup>349</sup> Electric Utilities Act, Section 5

<sup>350</sup> Article 9.8(c) and 9.9(f)

<sup>351</sup> Ex. 110, EPCOR.AESO-001 (a-c)

The AESO submitted the practice of collecting contributions prior to construction has been reinforced in subsection 29(3)(e) of the 2007 *Transmission Regulation*.<sup>352</sup> Sections 28 and 29 of the regulation read, in part, as follows:

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.

(2) The ISO must make reasonable efforts to ensure that the interconnection of a generating unit to the transmission system is undertaken in a timely manner.

(3) The owner of a generating unit that interconnects with the transmission system, and who has paid local interconnection costs, may not prohibit interconnection or access to the interconnection facilities by other market participants.

...

29(1) 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).

(2) The amount payable by owners of generating units is the sum of the following:

- (a) for upgrades to existing transmission facilities, a charge of \$10 000/MW;
- (b) a charge of not more than \$40 000/MW, as provided in the ISO tariff, payable by owners of generating units that locate in an area of the transmission system where generation exceeds load, and the amount of the charge is to be determined based on the location of the generating unit relative to load.

(3) 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 once only for that specific location and generating unit

...

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<sup>352</sup> Transmission Regulation, 29 (3) (e)

Intervenors argued that section 29 of the 2007 *Transmission Regulation* applied to system upgrades, not to local interconnection costs. They maintained that section 28 governed the collection of costs for the interconnection of generation facilities.

The AESO stated that the payment of the customer contribution has two primary benefits: providing a solid form of financial security for the construction of transmission facilities, and a meaningful demonstration of commitment from the customer. In addition, it offset the TFO's working capital, which is beneficial to all ratepayers.

Regarding the suggestions of EPCOR and TCE that providing a letter of credit or some other financial instrument be provided as a form of financial security, the AESO submitted that once the permit and license for an interconnection facility has been approved by the EUB and construction is about to commence, the concept of the customer contribution changes from being simply security to prepayment for service. Also, the AESO submitted that collection of cash contributions are a stronger form of security than a letter of credit when facilities are being purchased and constructed.

Lastly, the AESO noted that if the customer is concerned that future stages of the project may not proceed, or there are other financial considerations which impact their ability to pay the customer contribution associated with future capacity requirements, the customer can choose to simply contract for the first stage of their project and sign up for other phases in the future. The customer is then sending a clear signal to the AESO on the expected load requirements necessary for system development and the customer has the ability to manage their financial obligations associated with their project and interconnection to the AESO.

The Board considers there are two possible scenarios in relation to this issue. The first scenario is where the customer identifies all contemplated future expansion plans to the AESO, the AESO determines it is most economical to construct all facilities at once, and the facilities are constructed at the time of the initial contract. Should the customers' circumstances change in the future and a capacity increase be requested it would be treated as a separate project.

In this case the Board considers it reasonable to collect the entire customer contribution at the time of the initial contract. The Board appreciates that while the customer will be required to pay for facilities upfront which may not yet be required, this cost may be offset by potential cost savings that result from constructing all of the facilities at the same time. Consequent savings in the customer contribution may generally offset the increased carrying cost to the customer. If the customer requiring the facilities did not pay the contribution upfront then other customers would be in the position of cross subsidizing the customer requesting the facilities. The Board considers that such cross-subsidization would be an unfair result.

The second scenario is where the customer identifies future requirements to the AESO but the facilities for such requirements can be deferred until the time the customer contracts for the additional required capacity at a future point in time. The AESO considers that the customer contribution should be paid at the time of the initial contract in these cases as well.

Intervenors generally argued that supplying letters of credit or other such financial assurances from customers would provide the necessary demonstration of commitment and financial security required.

The Board has reviewed sections 28 and 29 of the 2007 *Transmission Regulation* and agrees with interveners that section 29 relates only to system upgrades. Section 28(1)(a) refers to local interconnection costs while section 29(2)(a) refers to upgrades to existing transmission facilities. The Board finds that section 29 is referring to system facilities that must be enhanced to accommodate additional generation. Section 28 is therefore the provision that is applicable. Unlike section 29, section 28 does not require the charge to be paid before commencement of construction. The Board therefore considers that section 28 allows the discretion to collect costs related to a local Point of connection (POC) on a staged basis.

The Board also agrees with the parties that allowing staged contributions for future capacity requirements would prevent a drain on scarce capital and is more in keeping with cost causation. The potential exists that supplying a letters of credit or other such financial assurance from a customer, should the customer be deemed to be credit worthy, may provide the necessary demonstration of commitment and financial security required by the AESO. The Board also considers TCE's suggestion that such funds be deposited in an interest bearing account to have merit.

While the Board believes that the adoption of staged payments is directionally appropriate, the Board is not convinced that sufficient evidence has been gathered to determine the extent to which letters of credit may or may not provide sufficient strength of financial security, the terms that any such letters of credit should involve, the nature and extent of other financial instruments that may be warranted, or what other measures may be warranted. Nor is the Board convinced that sufficient evidence has been gathered on the construction or other milestones at which staged payments should be made. Accordingly, the Board directs the AESO to conduct further analysis of the nature, amounts and milestones at which staged payments should be made, conduct such stakeholder consultations as it considers appropriate, and propose a tariff provision permitting staged contribution payments no later than the AESO's 2009 GTA or, if no such application is made, in its next GTA thereafter.

Given the above, the Board approves the AESO's proposed revisions to sections 9.2 and 9.7 of its T&Cs as reflected in the Application for purposes of this decision.

## **8.5 Contract Capacity Increases and Allocation**

In the Application, the AESO stated that during the AESO's stakeholder consultation process for the 2007 GTA, it had initially proposed a number of revisions to Article 13 to align AESO business practices with the tariff. It also undertook an additional stakeholder consultation process relating to business practices in respect of interconnection queue management and compliance milestones which may have an impact on Article 13. As such, the AESO proposed only two minor revisions to Article 13 at this time, to clarify:

- 1) a notice requirement for customers requesting an increase of their contract capacity at an existing POD or POS such that the notice must be in writing, and
- 2) that increases will be effective upon execution of the system access service agreement assuming sufficient transmission capacity can accommodate the requested contract capacity increase.

No objections to these proposed changes were received. The Board accepts the proposed changes as reasonable and they are approved as filed.

## 8.6 Reductions or Termination of Contract Capacity / Payments in Lieu of Notice

Article 14 of the AESO's T&Cs contains provisions regarding reductions in system access service contract levels and terminations of system access service. In the Application,<sup>353</sup> the AESO proposed changes to Article 14 to revise the manner in which lump sum payments in lieu of notice (PILONs) are determined for customers wishing to either reduce the capacity level of their system access service contracts or completely terminate those contracts.

The AESO stated that it had proposed changes to Article 14 to:

- clarify the details of how lump sum payments for contract level reductions or system access service terminations should be calculated;
- ensure that lump sum payments include the system charge but exclude the DTS POD charge;
- prescribe the use of the discount rate outlined in Article 9.14 of the T&Cs;
- clarify the prerogative of the AESO to revisit and revise the calculation of lump sum payment amounts in the event of material differences between requested contract and actual contract capacity.

The AESO submitted that its proposal to exclude the POD charge portion of the DTS rate when calculating a lump sum contract reduction or termination payment reflects the fact that the POD related portion of the charge is effectively captured by Article 9.9 of the T&Cs. Article 9.9 provides for a recalculation of customer contributions if a material change occurs in contract capacity. The AESO also noted that as the principles, rationale and importance of the five-year notice period endorsed in Decision 2005-096 continued to be reasonable, the AESO had not changed this requirement.

The evidence of Dr. Rosenberg on behalf of the ADC expressed concern about the AESO's proposed payment in lieu of notice provisions.<sup>354</sup> Dr. Rosenberg was opposed to exit fees in principle for several reasons. The concerns he expressed included (1) that such payments would not exist if transmission was provided as a competitive service since customers would not consent to bind themselves contractually; (2) unlike POD costs, bulk system and local system costs do not become stranded because new customers will use any capacity made available by a customer's exit; and (3) as a practical matter, it is difficult to estimate what the billing determinants of the exiting customer would have been if the customer had remained on the system.

Dr. Rosenberg suggested that a five year notice period would not likely assist planning since if an industrial customer finds it needs to shut down its operations for financial reasons, it will not know this five years in advance. Instead, Dr. Rosenberg suggested that it would be of greater assistance to the AESO's planning process to require that customers provide a good faith forecast of future service requirements.

The AESO, ADC, ASBG/PGA, DUC and CCA/PICA all presented arguments on payment in lieu of notice provisions. The views of parties in respect of payments arising from system access

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<sup>353</sup> Ex. 007, Section 6.7 of the Application, pp. 34-35

<sup>354</sup> Ex. 221, pp. 43-46

service reductions or terminations can broadly be classified into (1) submissions on the theoretical appropriateness of exit fees; and (2) in the alternative, proposed refinements to the AESO's tariff.

The primary theoretical arguments for or against exit fees primarily related to (1) the question of whether an exiting customer would, or would not be expected to create stranded costs; and (2) the question of whether the existence of exit fee provisions in the tariffs are of assistance to the AESO's long term system planning efforts.

With respect to stranded costs, the Board agrees with the ADC that potential for stranded costs on the bulk and local systems may be lessened during periods of strong economic growth and/or during periods when the transmission system is in the midst of a major expansion phase. However, the Board also agrees with the view of CCA/PICA that regardless of either the state of the Alberta economy or the ambitiousness of the AESO's transmission expansion plans, there can be no guarantee that system capacity released by a DTS customer will always, or necessarily even often, be replaced by another customer wishing to use that available system capacity within a reasonably short time. As a result, the Board considers that there will always be a potential that the exit of a customer will trigger stranded costs that must be borne by the AESO's remaining customers.

The Board agrees with the AESO that the CCA/PICA proposal to further investigate the notion of capacity swaps is inconsistent with Alberta's policy and legislative framework, which is not designed to reflect the notion of acquired capacity rights.

With respect to the question of the impact of exit fees on system planning, the Board disagrees with the ADC's view that exit fees do not assist the AESO in conducting long term system planning. The ADC's view does not take into account the problem of the free rider that may arise in any situation when the recovery of shared facility costs are widely disbursed among many customers. ADC's view also fails to account for the fact that some customers may benefit from receiving additional capacity that may greatly exceed the expected share of incremental costs that they pay.

There is no specific requirement that load forecasts provided by DTS customers in accordance with Article 8.2 of the AESO's T&Cs must correspond with the actual amount of capacity contracted for by DTS customers. However, the Board considers that the prospect of a customer being subject to an exit fee if it reduces its maximum DTS contract capacity or terminates its DTS contract emphasizes the importance of accurately forecasting the amount of contract capacity prior to making a capacity commitment. Thus, the amount of capacity contracted for by DTS customers at specific PODs is an important factor in system planning, the existence of exit fee provisions in the tariff generally has a positive effect on the accuracy of the AESO's system planning efforts.

Based on the foregoing, the Board finds that an exit fee mechanism is beneficial and economically supportable. Consequently, the Board remains strongly of the view that the continued provision of economic signals through an exit fee mechanism remains a desirable and appropriate aspect of the AESO's tariff.

The Board acknowledges DUC's suggestion that the PILON charge ought to take into account both the demand and energy portions of the DTS rate, to reflect that the higher energy charge

component of the AESO DTS rate design was justified in part to reflect cost causation differences between high and low load factor customers. However, in light of the Board's decision not to adopt the AESO's proposed A&E method, this issue does not need to be considered in respect of the PILON charge. The fact the AESO's proposed DTS rate design has not been approved also addresses the DUC proposal to base PILON charges on historical DTS billings that had occurred prior to the customer's notice of contract reduction or termination. The Board does not agree with DUC's proposal to reduce the number of years used to determine PILON charges from the current five years to two years.

The Board has not been persuaded at this time by the AESO's proposal to eliminate the POD charge component from the determination of PILON charges. While the Board agrees that Article 9.9 of the T&Cs provides for a recalculation of customer contributions if DTS capacity is reduced, the AESO has not proposed to eliminate the POD charge portion of the DTS rate for a DTS customer who elects to continue to pay DTS rates rather than make a lump sum payment. However, the wording of Article 9.9 is not overly prescriptive as to the how the exact amount of any revised customer contribution is to be calculated to reflect changes in a customer's DTS contract capacity. Accordingly, if the AESO believes that continuing DTS charges could cause a double collection, the AESO may take this into account as appropriate into any calculations made in accordance with Article 9.9. As the AESO has included in its Article 14 PILON only the system charge portion and not the POD charge portion of the DTS rate, no additional Board direction is required.

Finally, the Board rejects the ADC's proposal that if a customer chooses to manage a contract reduction or termination through the "ride out" option (by continuing to be subject to DTS charges for the five years following the provision of notice), that customer's rates should be based on the DTS rates in effect at the time of notice. The Board finds this option to be unnecessary, since the customer's risk of future DTS rate changes can be mitigated by selecting the lump sum PILON charge option.

## **8.7 Regulated Generating Unit Connection Charge**

In section 6 of the Application, the AESO described its proposed revisions to Article 14 of its T&Cs to address the applicability of the regulated generating unit connection cost (RGUCC) component of the STS rate if a regulated generating unit (RGU) terminates its system access service contract prior to the expiry of the RGU's base life as indicated in the tariff.<sup>355</sup> This included a proposal to charge new generators an additional charge based on the replacement cost new (RCN) of the existing interconnection facilities previously used by a regulated generator that has ceased operations.

The AESO noted that prior Board decisions<sup>356</sup> had established the RGUCC to establish a "level playing field" between the generators that were required to pay their own interconnection costs and the previously regulated generators (for which the interconnection costs were part of embedded transmission costs). However, the AESO considered that as and when a previously regulated generator no longer produced electric energy, the RGUCC no longer served any economic purpose. Accordingly, the AESO submitted that the RGUCC should not continue to

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<sup>355</sup> The base lives of RGU's are set out in the rate appendix of the AESO's proposed tariff. See Ex. 008, pp. 50-52.

<sup>356</sup> Citing Decisions 2000-1 and 2002-048

apply after a previously regulated unit has been decommissioned. To clarify this intent, the AESO proposed a new Article 14.6 of the T&C which would provide that:

- payment of the RGUCC would no longer be required if a unit stops generating energy;
- to avoid payment of the RGUCC, physical dismantling of a facility would be required (rather than simply shut down);
- if the regulated unit was to be re-powered up, or if a new unit was to be developed on the same site using the same interconnection facilities, the RGUCC would apply up to the Base Year.

The AESO proposed further changes to Article 14.6 in its February 14, 2007 errata filing no. 1,<sup>357</sup> to address considerations it had identified in response to EPCOR.AESO-002(e).<sup>358</sup>

EPCOR argued that there were a number of significant concerns with the AESO's proposed revisions to Article 14.6. Its primary objections were that:

- it is not just and reasonable for the AESO to impose costs through the tariff that bear no relationship to original cost;
- the AESO should respect the Board's determination with respect to the amortization of deemed interconnection costs of formerly regulated generators;
- generators should be able to connect to the system in a manner which reduces incremental costs to the system and should not be confronted with additional non-cost based charges after investment decisions have been made.

EPCOR submitted that the AESO's proposal to charge new generators an additional charge based on the RCN of the existing interconnection facilities would be contrary to section 121 of the EUA, which requires the Board to ensure that a tariff is just and reasonable, not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the EUA or any other enactment or law. In support of this contention, EPCOR submitted that:

- the imposition of a charge based on the RCN of the existing facilities would not be just and reasonable and contrary to original cost regulation because it would disregard the Board's findings in Decision 2000-1<sup>359</sup> regarding the deemed cost and amortization period for regulated generation interconnection facilities;
- the imposition of RCN, in addition to the incremental connection costs established pursuant to Article 9.3(c) of the T&C's, would be arbitrarily and unjustly discriminatory;
- the imposition of RCN, on top of the obligation to pay incremental connection costs, is contrary would contravene a central purpose of the EUA which is to establish a flexible framework in which electricity generation investments are guided by competitive market forces.

The Board does not agree with the AESO's proposal to apply a charge based on a determination of RCN (or RCN less accumulated depreciation) for the interconnection facilities previously used by a regulated generator that has ceased operations.

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<sup>357</sup> Ex. 197

<sup>358</sup> Ex. 173

<sup>359</sup> Decision 2000-1 ESBI Alberta Ltd. 1999/2000 General Rate Application Phase I and Phase 2 (Application 990005) (Released: Feb 2, 2000)

The Board acknowledges the AESO's view that interconnection facilities previously used by regulated generators that have ceased operations may, in theory, be redeployed to other locations within the transmission system of the TFOs.<sup>360</sup> However, the Board also notes that in order to benefit from such redeployment, costs will likely have to be incurred for both the salvage and remediation of the original interconnection and from the installation costs incurred to use salvaged facilities in a new location. The Board is therefore persuaded that if a new generator can avoid costs by using an existing interconnection, there may be a benefit to Alberta rate payers from doing so.

The Board agrees with EPCOR that there is neither a policy mandate nor an economic rationale to, in effect, impose an additional round of level playing field considerations in an effort to equalize the opportunities of generators using interconnection facilities originally developed for regulated generators with the opportunities of other generation developers that do not use such facilities. The Board considers that a new generator who does not use an existing interconnection and may have to pay more than a generator that does use an existing interconnection is not unlike a generator that locates close to the existing transmission network and so incurs lower interconnection costs than a generator that locates farther away and so must build a longer radial line.

In accordance with the above, the Board approves the AESO's proposed revisions to Articles 14.6(a) and 14.6(b) as set forth in section 7 of the Application.<sup>361</sup> The Board denies the AESO's proposed Article 14.6(c) as set out in section 7 (and subsequently augmented to include article 14.6(c)(iii) as described in the AESO's February 14, 2007 errata filing).<sup>362</sup> The Board directs the AESO to include the final version of Article 14.6 reflecting the Board's decision at the time of its refiling application pursuant to this Decision.

EPCOR expressed concern with the application of an additional RCN charge to the new units it has determined to install at Clover Bar, and noted that its investment decision to install the new units at Clover Bar has already been made.<sup>363</sup> The AESO replied that when it learned that the Clover Bar unit would be terminating service, its first response was that the outstanding RGUCC charges would apply to the end of the base year life for the unit. However, at the request of EPCOR, the AESO subsequently reviewed its response, and determined that the RGUCC charge would not apply in that case beyond the termination date of the Clover Bar power purchase arrangement (PPA).<sup>364</sup>

EPCOR did not file any evidence in this proceeding. Based on the limited record of this proceeding, the Board is not persuaded that any decision that may have been made by the AESO to suspend the RGUCC coincident with the termination of the Clover Bar PPA (Power Purchase Arrangement) would have been consistent with the tariff in effect at the time. In addition, based on the limited facts presented during the proceeding, it is also not apparent to the Board that suspension of the RGUCC charges coincidence with the termination of a PPA would be either

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<sup>360</sup> Tr. Vol. 2, pp. 389-390

<sup>361</sup> Ex. 008

<sup>362</sup> Ex. 197, p. 3

<sup>363</sup> EPCOR Argument, p. 3

<sup>364</sup> AESO Reply, p. 38

necessary or appropriate for the purposes of maintaining a level playing field between generators subject to the RGUCC and generators built after the end of the regulated generation era.

## 8.8 Peak Metered Demand Waivers

Article 16 of the T&Cs describes the AESO's ability to waive a customer's metered demand for billing capacity calculation purposes in certain specified circumstances. Fortis Alberta Inc (FAI) asked a number of information requests of the AESO respecting the circumstances under which the AESO would grant peak metered demands waivers for distributors. In general, FAI sought to clarify how Article 16 of the T&Cs would be applied operationally by the AESO.

In its supplemental filing dated May 1, 2007,<sup>365</sup> the AESO indicated that following discussions with FAI, it had gained a greater understanding of FAI's concerns. As a result of such discussions, the AESO indicated that the peak demand waiver provisions could reasonably be modified to accommodate limitations in the information available to Discos which could complicate the provision of notice in advance of temporary POD peaks related to maintenance activities.

In the supplemental filing, the AESO proposed a revision to Article 16.1(b) of the T&Cs to reflect its improved understanding of FAI's concerns.

In argument, the AESO noted that after submission of its supplemental filing, neither FAI nor any other party subsequently pursued peak metered demand waiver issues. Accordingly, the AESO submitted that Article 16, with the revisions set forth in its supplemental filing, should be approved. In its argument submission, FAI indicated that as a result of discussions with the AESO, its concerns had been addressed.

As noted in AESO information request responses,<sup>366</sup> the Board has addressed the appropriate flexibility in respect of peak metered demand waivers in prior transmission tariff decisions. It is appropriate that reasonable flexibility be exercised in respect of peak metered demand waivers. In general, to the extent that POD peaks arising from Disco maintenance activities do not trigger increases in the amount of either bulk or local system capacity planned by the AESO, the Board considers that it is reasonable for the AESO to grant peak demand waivers.

In light of the above, the Board approves Article 16, as amended by the supplemental filing (Exhibit 349). The Board directs the AESO to file its revised Article 16 incorporating the Exhibit 349 changes in its refiling application pursuant to this Decision.

## 8.9 EPCOR Reactive Power Issue

EPCOR raised a concern with the potential impact on EPCOR's rights and obligations under its power purchase agreements of new reactive power requirements arising from the AESO's generation and load interconnection standard. EPCOR did not file evidence in support of its concerns, but rather used a series of hearing exhibits to advance cross examination of the AESO panel in respect of this issue. EPCOR did not propose any changes to the AESO tariff.

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<sup>365</sup> Ex. 349, p. 4

<sup>366</sup> FAI.AESO-001(f) (see Ex. 111) notes that peak metered demand waivers previously dealt with by the Board in Decision 2000-1 (p. 215) and Decision 2001-32 (p. 171)

EPCOR and the AESO have indicated their willingness to attempt to resolve the reactive power related concerns through direct negotiations. The Board supports such discussions. However, the parties did not discuss how any reactive power related matters might be resolved if the direct discussions did not result in a resolution.

The Board is not convinced that the reactive power issue raised by EPCOR is a tariff matter. While the AESO's transmission interconnection requirements are defined in Article 1.1 of the AESO's T&Cs, those requirements comprise a number of complex, detailed and technical documents which have been implemented by the AESO pursuant to its rule making authority. As such, should it be necessary in the future for this matter to be brought before the Board, the Board questions whether it may be more effectively raised outside a tariff proceeding, such as pursuant to the complaint provisions of section 25 of the EUA. The Board also encourages the parties involved to consider using the dispute resolution provisions contained in Article 19 of the T&Cs, if applicable.

## **9 RESPONSES TO OUTSTANDING BOARD DIRECTIONS**

### **9.1 Compliance with Board Directions**

In section 8.1 of the Application, the AESO provided a matrix that itemized Board directions from Decision 2005-096 and other recent decisions related to the AESO's tariff. The matrix provided a brief description of the outstanding direction and indicated where the direction had been addressed in the Application or when the direction would be addressed in a future GTA or other future AESO application.

The matrix used a numbering scheme that does not necessarily correspond to the direction numbers assigned by the Board in Decision 2005-096, and included certain Board directions set out in Decision 2005-096 that had not been included in the directions summary provided in Appendix 2 of that Decision.

This numbering scheme was derived from the direction numbering used by the AESO in its refiling application arising from Decision 2005-096 (Application 1420890), and is reproduced as Appendix 5 to this Decision. The refiling application arising from Decision 2005-096 was ultimately approved by the Board in Decision 2005-131.<sup>367</sup> For the purposes of this Decision, in order to assist parties in cross referencing outstanding directions arising from Decision 2005-096 and other relevant AESO decisions, the Board has adopted this numbering scheme.

Nothing in this Decision shall relieve the AESO of directions arising from the Article 11 Proceeding. Unless otherwise noted in this Decision, the Board considers that the AESO's obligations in respect of directions described in Appendix 5 to this Decision have been fulfilled.

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<sup>367</sup> Decision 2005-131 - Alberta Electric System Operator (AESO) Refiling of 2005/2006 General Tariff Application per Decision 2005-096 (Application No. 1420890) (Released: December 6, 2005)

## 9.2 Harmonization of AESO and Disco Contribution Policies

In section 8.4 of the Application, the AESO noted that certain directions in Decision 2005-096 required the AESO to advance harmonization of the customer contribution policies and service standards of the AESO and the Discos.

The AESO noted that pursuant to directions 12A and 22 from Decision 2005-096, in December 2005 it had initiated a consultation process by circulating a discussion paper outlining various issues being considered by the AESO for the 2007 GTA.

While the AESO submitted that the degree of harmonization in its tariff is adequate, the AESO also noted that it was contemplating a proposal whereby all Discos would be required to add a stipulation within their terms and conditions that would not permit an investment amount higher than the most economic and technically viable solution, thereby mirroring Article 9.1 of the AESO's tariff and creating indifference between any requested level of service. The AESO indicated that it was its intention to present this proposal to the Discos and to report to the Board as part of its 2008 GTA or at another appropriate time.

The AESO noted that while some Discos had questioned the interpretation of AESO standard facilities and consequential impacts within the contribution policy, the present process guidelines have greatly increased harmonization between the AESO and Discos.

The Board is encouraged by the AESO's efforts to comply with these directions and considers that the requirements of the harmonization related directions from Decision 2005-096 have been addressed in full. As such, while the AESO may choose to continue discussions with Discos, which were originally commenced to comply with the Board's 2005-096 harmonization directions, the Board direction to continue to do so is no longer required.

The AESO made a preliminary suggestion that it might propose, as part of its 2008 GTA or in another future process, that Discos adopt a provision similar to Article 9.1 of the AESO's T&Cs as part of their respective T&Cs. While this proposal received little attention within the present proceeding, given the Board's findings in section 8.2.1 of this Decision, the Board is not persuaded at this time that such a change would be necessary.

To the extent that the interconnection process guidelines are followed, the Board is not persuaded at this time that a direction to the Discos to include provisions mirroring Article 9.1 of the AESO T&Cs is necessary.

## 9.3 Consideration of TFO O&M Costs of in Future Cost of Service Studies

In the outstanding directions summary matrix, direction 4D is described as pertaining to TFO O&M costs that may be energy related. It further indicates that direction 4D is to the subject of a future study and that section 4.3.3 of the Application addresses related AESO initiatives.

While the AESO's directions summary matrix indicates that direction 4D was specified in Decision 2005-096, it was not included in the summary of Board directions set out in Appendix 2 of that decision. The AESO appears to have inferred a Board direction from the following passage of Decision 2005-096:

However, the Board also considers that a reasonable portion of TFO costs are related to O&M and that a material percentage of these may be energy related. Unfortunately, the impact of this factor does not appear to have been researched in this current study and therefore the Board cannot draw a firm conclusion respecting its impacts on the demand charge. Nonetheless, based upon the percentage that O&M expenses comprise of a TFO's revenue requirement, the Board considers that such an analysis would support a reasonable classification of costs as energy related. The Board expects the AESO to address these issues in future cost of service studies.<sup>368</sup>

A Board direction related to further study of TFO O&M costs was set out in section 5.7.8.3 of this Decision. However, the TCCU indicates that insufficient data is presently available on which to base a proper allocation of TFO O&M costs by function, vintage or equipment type. The TCCU also suggests that the impact of functionalizing TFO O&M costs is likely to be small.<sup>369</sup>

In light of the above and in light of the Board's direction in section 5.7.8.3 of the Decision, the Board finds that compliance with Direction 4D is not required at this time.

#### **9.4 Amended Internal Controls Pursuant to Decision 2006-046**

In Decision 2006-046,<sup>370</sup> the Board dealt with a complaint against the AESO filed by TCE with respect to TCE's Marlboro project. During the course of that proceeding, it came to the Board's attention that certain lapses in internal control occurred in the AESO's handling of EnCana's Countess project. As a result, the Board directed the AESO to review its internal controls with a view to improving its controls so that similar errors would be prevented in the future.

In the Application, the AESO noted that the Countess project was energized in September 2003, prior to the AESO's development and implementation of a new customer interconnection process completed in March 2005.<sup>371</sup>

The Board has reviewed the information provided by the AESO with respect to the controls inherent in the interconnection process and considers that, for the Board's purposes, they satisfactorily address the direction contained in Decision 2006-046.

The Board also notes that Decision 2006-046 stated the following:

The Board observes that Article 9.7(b) of the AESO T&C in effect at the time of the Countess Facility allows for a customer contribution to be recalculated if actual contract capacities are materially different than originally projected, while Article 9.7(d) allows for recalculation in case of a material error in the original calculation. Article 9.9 of the most recently approved T&C contains similar provisions. In the Board's view, it is reasonable for the AESO to consider these Articles with a view to reassessing and applying appropriate charges with respect to the original contribution paid by EnCana in respect of the Countess Facility.

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<sup>368</sup> Decision 2005-096, p. 23

<sup>369</sup> Ex. 012, pp. 54-55

<sup>370</sup> Decision 2006-046 - TransCanada Pipelines Limited Complaint Against Alberta Electric System Operator (AESO) Application of AESO Contribution Policy (Application No. 1431750) (Released: May 12, 2006)

<sup>371</sup> Ex. 009, Application Section 8.5, pp. 10-12

The Board directs the AESO to report its progress with respect to this matter to the Board by June 15, 2006.

The Board directs the AESO to provide an update, in the refiling, as to the specific actions taken and the final payments made in respect of this matter.

## **10 ORDER**

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

- (1) The AESO shall refile its 2007 General Tariff Application to reflect the findings, conclusions and directions in this Decision on or before February 1, 2008.

Dated in Calgary, Alberta on December 21, 2007.

### **ALBERTA ENERGY AND UTILITIES BOARD**

*(original signed by)*

T. McGee  
Presiding Member

*(original signed by)*

Laurie J. Bayda  
Acting Member

*(original signed by)*

Douglas A. Larder, Q.C.  
Acting Member



**APPENDIX 1 – HEARING PARTICIPANTS**

<b>Principals and Representatives (Abbreviations Used in Report)</b>	<b>Witnesses</b>
Alberta Electric System Operator (AESO) J.H. Smellie	Alberta Electric System Operator (AESO) H. Kirrmaier, P. Eng. J. Martin, P. Eng. E. Hucman A. Reimer, P. Eng.
Alberta Direct Connect Consumer Association (ADC) R. C. Secord	Alberta Direct Connect Consumer Association (ADC) A. Rosenberg, PhD (Mathematics) C. Kearl, P. Eng. A.J. World, CMA
ATCO Electric (AE) L. G. Keough A. M. Sears	ATCO Electric (AE) P.G. Goguen, P. Eng., MBA C.L. Clark, P. Eng.
Alberta Sugar Beet Growers and Potato Growers of Alberta (ASBG/PGA) J.H. Unryn	
BC Hydro and Powerex Corp. (Powerex) L.L. Manning	
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Dual-Use Customers (DUC) M.S. Forster	Dual-Use Customers (DUC) D. Hildebrand, P.Eng., MBA D. Chesterman, P. Eng.
Dual-Use Customers / TransCanada Energy Ltd. (DUC/TCE) M.S. Forster A.R. Avery	Dual-Use Customers / TransCanada Energy Ltd. (DUC/TCE) D. Hildebrand, P.Eng., MBA D.J. Levson, P. Eng. M. Young, P. Eng. C. Best
EPCOR Energy Services Alberta Ltd. (EPCOR) J.E. Lowe	
FortisAlberta Inc. (FAI) T. Dalgleish, Q.C.	
Independent Power Producers Society of Alberta (IPPSA) A. Slager	
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	Industrial Power Consumers Association of Alberta (IPCAA) R. Mikkelsen, P. Eng., MBA M. Drazen D. Macnamara, LLB
Pipeline Power Group and Associates (PPGA) L.. G. Keough A. M. Sears	Pipeline Power Group and Associates (PPGA) C. Carlsen, B.Sc. Eng. S. Stoness, B.Sc. Eng., MBA

<b>Principals and Representatives (Abbreviations Used in Report)</b>	<b>Witnesses</b>
	E. de Palezieux, MBA J. Shand, P. Eng., MBA
Public Institutional Consumers of Alberta (PICA) N.J. McKenzie	Public Institutional Consumers of Alberta (PICA) R. Retnanandan, CPA
TransAlta Corporation (TAU) T. Dalgleish, Q.C.	
TransCanada Energy Ltd. (TCE) A.R. Avery N.E. Berge	D.J. Levson, P. Eng. K. Tate, MA, MBA J. Alexander, CFA C. Best
Utilities Consumer Advocate (UCA) C. R. McCreary R.B. Henderson	
Board Panel T. McGee, Presiding Member L. J. Bayda, Acting Member D. Larder, Q.C., Acting Member	
Board Staff S. Wakil, Board Counsel C. Wall, Board Counsel J. Cameron, CGA J. Halls D. Ploof C. Taylor	

## APPENDIX 2 – SUMMARY OF BOARD DIRECTIONS

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

1. In the Board's review of the AESO 2007 revenue requirement forecast, it has not identified any significant concerns which would require modifications. The Board directs the AESO to continue its practice of updating its forecast of wires related costs to reflect any interim or final approvals granted to TFOs in its refiling application. Subject to this qualification and subject to the application of the appropriate tests during the deferral account process, the Board approves the AESO 2007 revenue requirement forecast as applied for..... 11
2. The Board directs the AESO to compare the value of the additional TCCU refinement recommendations proposed by PS Technologies against the cost of performing the additional research, present the results in its next GTA, and to propose at its next GTA any refinements it considers warranted. .... 25
3. The AESO is directed to continue to unbundle bulk and local wires costs and to use the 12 CP method as the allocator for collecting the demand portion of bulk wires costs..... 35
4. The Board therefore directs the AESO to continue the use of NCP, together with the current ratchet, for purposes of allocating and collecting the demand portion of local system wires costs..... 35
5. The Board directs the AESO to reflect the Board approved linear POD cost function in the AESO refiling as noted below: ..... 55  

$$Y = \$0.894 \text{ million} + \$0.503 \text{ million/MW for the first } 7.5\text{MW} + \dots\dots\dots 55$$

$$\$0.174 \text{ million/MW for the next } 9.5\text{MW} +$$

$$\$0.102 \text{ million/MW for the next } 23\text{MW} +$$

$$\$0.054 \text{ million/MW for all MW above } 40.0\text{MW}.$$
6. In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs. .... 59
7. The AESO is directed to reflect the above in its refiling. Based upon the information the AESO has been directed to provide in the refiling, the Board will determine what, if any, rate mitigation measures are necessary..... 61
8. The Board has, in section 5.0 of this Decision, directed the AESO to modify its proposed cost allocation and rate design. Based on the expert evidence put forth in this proceeding, the Board does not consider that these changes are likely to result in rate impacts to a significant number of the individual PODs served by the AESO when compared to the existing 2006 rates, however the Board recognizes that the potential exists. .... 62
9. Therefore, the Board directs the AESO to prepare bill impacts that compare the bills which result from the directions in this Decision to the current Board approved tariff. The bill

- comparison will include all components of a customers' bill, including commodity costs, similar in format to Board information request BR-AESO-003. The pool price assumed for the commodity charge is to be the same for both periods so that the comparison isolates the increase attributable to transmission costs only. All other assumptions used in developing the results and the impact of those assumptions are to be included in the analysis. For any POD receiving an increase of greater than 10% (in comparison to the 2006 tariff), the Board directs the AESO to provide the nature of the customers served by each POD (whether Disco, direct connect, or a Disco customer on a flow through rate), the total dollar impact to the POD and the total amount it would cost to subsidize all such PODs down to the 10% increase level..... 63
10. In summary, the Board considers that these PSC rates appropriately credit to customers the amount of the POD charge that is related to facilities they have provided while at the same time ensuring they make a contribution to the cost of non-transformation assets provided for customers. The AESO is directed, in its refiling application, to make the necessary adjustments to the PSC rate to reflect the rates approved by the Board in this Decision. .... 66
11. The AESO is directed in its refiling application to amend the PSC rate schedule to reflect the Board's findings that eligibility for the PSC is to be restricted to dual use customers and those unconventional interconnections described by the AESO in section 4.5.2 of the Application. Isolated generating units will not be eligible ..... 68
12. The Board therefore directs the AESO, as part of its refiling application, to propose an updated DOS 7 minute rate that is based on both usage costs, as approved by the Board, and a contribution to fixed costs. The Board expects the AESO to develop a proposed level for the DOS 7 minute rate that it considers appropriate and notes that a rate in the order of 6% lower than the current DOS 7 minute rate would be consistent with the overall DTS rate decrease of 6%. ..... 74
13. The Board therefore directs the AESO, as part of its refiling application, to propose new DOS 1 hour and DOS term rates, using the same concepts as contained in the DOS rate design section of its of the Application with respect to the cost differential it considers appropriate for all of its DOS rates, given their associated curtailment and contractual characteristics, and to indicate its rationale supporting those rates. .... 74
14. No party commented upon rate FTS. However, the Board has in this Decision directed that certain changes be made to the DTS rate. In particular the Board has directed changes to the classification of wires costs. To retain the alignment between rates DTS and FTS, the Board considers it may be necessary for the AESO to make changes to rate FTS in its refiling application. The AESO is therefore directed, in its refiling application, to review the Board directed changes to rate DTS and to propose any amendments necessary to rate FTS to retain alignment with rate DTS, and to indicate its rationale supporting its proposal..... 75
15. In reply argument, the AESO stressed the value of continuing to develop an ..... 83
16. Therefore, in accordance with figure 4 on p. 36 of TCE's evidence, the Board finds that the minimum charge in Rate XOS 1 Hour is to be set at \$3.98 per MW/h and that Rate XOS 1 Month is to be set at \$4.36 per MW/h. The AESO is directed to make all necessary adjustments to its export opportunity rate schedules and any associated T&Cs to reflect the above findings at the time of its refiling application. .... 87
17. No party expressed any concern with respect to this rate. The Board finds the AESO proposal to be reasonable and it is approved as filed. .... 87

18. Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO’s 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO’s advancement of the cost study used in support of the AESO’s revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, \$0.12 of incremental TFO O&M costs will be generated by each \$1.00 of capital investment in an interconnection facility. However, additional research into the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA. .... 106
19. In light of the above, the Board finds that the wording of Article 9.4 as approved in Order U2005-464 remains for the most part appropriate. However, to avoid potential confusion arising from the use of the word “prepaid”, the Board directs the AESO to amend Article 9.4 as indicated below, and to include this revised wording for Article 9.4 in updated T&Cs to be provided with the AESO’s refile application: ..... 107
- 9.4 Operations and Maintenance..... 107
- For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of: ..... 107
- (a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and..... 107
- (b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer. .... 107
20. While the Board believes that the adoption of staged payments is directionally appropriate, the Board is not convinced that sufficient evidence has been gathered to determine the extent to which letters of credit may or may not provide sufficient strength of financial security, the terms that any such letters of credit should involve, the nature and extent of other financial instruments that may be warranted, or what other measures may be warranted. Nor is the Board convinced that sufficient evidence has been gathered on the construction or other milestones at which staged payments should be made. Accordingly, the Board directs the AESO to conduct further analysis of the nature, amounts and milestones at which staged payments should be made, conduct such stakeholder consultations as it considers appropriate, and propose a tariff provision permitting staged contribution payments no later than the AESO’s 2009 GTA or, if no such application is made, in its next GTA thereafter. .... 111
21. In accordance with the above, the Board approves the AESO’s proposed revisions to Articles 14.6(a) and 14.6(b) as set forth in section 7 of the Application. The Board denies the AESO’s proposed Article 14.6(c) as set out in section 7 (and subsequently augmented to include article 14.6(c)(iii) as described in the AESO’s February 14, 2007 errata filing). The Board directs the AESO to include the final version of Article 14.6 reflecting the Board’s decision at the time of its refile application pursuant to this Decision. .... 116
22. In light of the above, the Board approves Article 16, as amended by the supplemental filing (Exhibit 349). The Board directs the AESO to file its revised Article 16 incorporating the Exhibit 349 changes in its refile application pursuant to this Decision..... 117
23. The Board directs the AESO to provide an update, in the refile, as to the specific actions taken and the final payments made in respect of this matter. .... 121

### APPENDIX 3 – SUMMARY OF KEY FINDINGS

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

1. Subject to any statements made by the Board to the contrary in the remainder of this Decision, the Board considers the AESO has appropriately addressed the requirements of the relevant legislation. .... 8
2. The Board is encouraged that the AESO is taking action to resolve its deferral accounts and considers that no further Board directions are required at this time. .... 12
3. The rate design principles of cost causation and rate shock avoidance are not of equal importance. Effectively, PPGA’s approach imposes a pre-condition on the use of cost causation as the pre-eminent rate design principle if a proposed rate change creates a significant change in the rates paid by specific customers. However, as articulated in Decision 2005-096, the Board re-affirms that cost causation should also receive pre-eminent consideration amongst Bonbright principles as applied to the design of the POD charge. Thus, while rate shock remains a valid consideration in the design of any rate, including the POD charge, rate shock should be addressed as a separate stand alone issue after cost causation has been determined. The Board deals with rate shock in section 5.9 of the Decision. .... 15
4. The Board concludes that it cannot accept the hypothesis as posited in the TCCU, and as supported in Appendix D. The Board does not accept that for Alberta as a whole, the correlation between the time of maximum stress on the bulk system and the hour of AIL peak system load is weak or non-existent. The Board also does not accept that for most areas of Alberta, the time of maximum stress on the bulk system does not coincide with the time of the annual peak system load. .... 22
5. For these reasons, the Board rejects the hypothesis that there is a weak correlation between circuit load and the system peak. The Board considers that system peaks are more important than load in every hour. The transmission system is planned for peak load. As acknowledged by the AESO under cross examination by Mr. Secord, peak load is the primary cause of maximum stress. The transmission system must be planned and built to withstand this stress. It follows that peak load is the cause and primary driver for bulk system costs. Given that peak load is the primary driver for bulk system costs, the Board finds that it is the primary basis on which costs are to be allocated. .... 24
6. The Board has in section 5.2 above rejected the hypothesis that there is a weak correlation between circuit load and the system peak. The Board considers that system peak is more important than load in every hour. The Board continues to be of the view that unbundled costs (that is, separate rate components for bulk and local wires) will allow the flexibility to design rates more reflective of cost causation and allow for more appropriate and effective price signals to customers. The Board therefore rejects the AESO proposal to rebundle bulk and local wires costs in the DTS rate design. .... 26
7. For the above reasons the Board rejects the use of the proposed A&E method. The Board finds that transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges. .... 30

8. The Board finds that bulk and local wires should both be classified as 18% energy related, the upper end of the zone of reasonableness established by the evidence, and collected on an all hours energy basis as one energy charge. As stated above, the Board considers that a portion of wires costs are energy related. The Board also considers the TCCU to be the best available evidence as to what that portion should be. The remaining 82% of the costs related to bulk and local wires are to be classified as demand related. This is consistent with both the evidence contained in the TCCU, and the principle that rates should reflect cost causation. The Board finds that this will also provide more effective price signals to consumers than will the proposed A&E method. .... 32
9. The Board is interested in the real price signal being received by real customers. With respect to this, Mr. World, a witness for the ADC, was the only customer to present testimony as to the price signal being received by customers and the actions customers are taking as a result of the signal being sent by the use of the CP method. The Board finds the testimony of Mr. World to be both credible and instructive. Clearly it is not possible for a customer to generally simply turn the power off and completely avoid the hour of system peak as the AESO has suggested above. The Board acknowledges that the primary goal may be to reduce energy costs. However, it is equally clear that customers are already motivated to shift load to achieve a flatter load profile, which is exactly the behaviour the AESO claims it wishes to induce. The Board also notes that the use of the 12 CP method would be more consistent with past Board approved rate design. For the above reasons the Board rejects the use of NCP as the allocator for bulk system costs..... 34
10. The Board considers there to be considerably less diversity on the local system than the bulk system. The Board finds that the use of a ratchet at the local system level is a fair and efficient means to ensure recovery of those fixed costs caused by the relatively few, non-diverse customers present at any point on the local system..... 35
11. No party raised concerns with the treatment of ancillary service costs contained in the Application. Subject to such determinations as the Board makes elsewhere in this Decision and subject to such adjustments that may be made in the Article 11 Proceeding to interim payments made under Article 11, the AESO's proposed treatment is approved as filed. .... 36
12. The Board addresses each of the above issues in the following sections of this Decision. In summary, in the remainder of this section 5.7 of the Decision, the Board has found that: .... 37
- the AESO has investigated POD costs as required by Decisions 2005-096 and 2005-132; ..... 37
  - it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO's contribution policy; .. 38
  - the impact of economies of scale on POD costs is significant as capacity increases and is to be reflected in the POD cost function and design of the POD charge;..... 38
  - it is appropriate to use the best available data to determine the POD cost function for the purposes of both the POD charge and the AESO's contribution policy;..... 38
  - the statistical fit of the POD cost function approved by the Board in section 5.7.7 of this Decision was sufficient to support its use for both POD charge and contribution policy purposes; ..... 38
  - a non-linear function best describes the of POD cost economies of scale; ..... 38
13. The Board considers that its finding that cost causation is the rate design criterion to be afforded the most weight applies to the POD charge and not solely to the rate design for recovering bulk and local system costs..... 40

14. The PPGA’s submissions placed considerable focus on differences between embedded historical costs and a forward looking POD cost function devised to set maximum investment allowances under the customer contribution policy. However, the PPGA did not substantiate its claim. As a result, the Board is unable to conclude that the shape of a historical POD cost function and a forward looking POD cost function would be materially different. .... 42
15. However, DUC observed that it is generally at larger PODs where additional transformers are more likely to be deemed desirable. Thus, the Board considers that any potential distortion of the cost causation principle arising from the use of a POD cost function based on only standard facility costs tend to occur in larger rather than smaller PODs, since multiple transformers tend to exist only in larger PODs. As noted by DUC in argument, four of the five historical cost data points (supplied by the AESO) represented PODs with more than one transformer. Therefore, as the Board has used the cost data for the five PODs referred to by DUC for its approved POD cost function, the underlying shape of the cost function for POD charge purposes does not differ from the POD cost function used for the purposes of the contribution policy’s maximum investment function. Thus, the Board finds that it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO’s contribution policy..... 42
16. The Board agrees with DUC that the average cost of transmission interconnections will exhibit significant economies of scale with increasing capacity. The Board further concludes based on the evidence provided by DUC that a POD cost function expressed as dollars per MW should be non-linear in shape in recognition that certain components of POD costs (most notably the cost of transformers) tend to increase at a decreasing rate with the capacity of the interconnection. .... 44
17. Using 13 all POD dataset data points to represent PODs with capacities below 7.5 MWs and an additional five all POD dataset data points to represents PODs with capacities greater than 43.2 MWs raises issues with respect to its comparability with the greenfield dataset. However, the Board finds these additional data points are the best available POD cost data for projects in these contract capacity ranges. Moreover, since the Board is strongly persuaded that the relationship between POD costs and contract capacity will exhibit economies of scale, the Board considers that a much more significant distortion of the POD cost function would occur if these data points were to be excluded than any potential for distortion that may be caused by incompatibilities with the greenfield data. Thus, in section 5.7.7 below, the Board uses this augmented 48 POD dataset as the basis for the POD cost function approved by the Board..... 46
18. While the statistical fit may not be high, the Board does not consider that statistical analysis should be discarded solely on the basis that  $R^2$  values fall in the lower range. All things equal, the Board considers that a significantly higher  $R^2$  value is generally preferable to a function with a lower  $R^2$  value as long as the resulting POD cost function appears to reasonably reflect underlying cost relationships such as the effects of economies of scale described in section 5.7.4 above. .... 46
19. For these reasons, the Board finds that the POD cost function developed by Board staff that was released for comment on October 25, 2007 is the function to be used by the AESO. .... 55
20. Given the foregoing, the Board does not accept the PPGAs proposal to reduce POD costs by \$3.6 million to reflect the functionalization of high-side breaker costs from POD to local... 57
21. Given the foregoing, the adjustment to the POD charge cost function proposed by CCA/PICA is denied..... 58

22. The Board's findings and directions can be summarized as follows:..... 60
- The functionalization of transmission costs as illustrated in section 4.3.5 of the Application is approved as filed. .... 60
  - Bulk and local wires costs are to be classified as 82% demand related and 18% energy related..... 60
  - The rate design shall collect the 18% energy related costs of bulk and local wires costs on the basis of an all hours energy charge. .... 61
  - The demand portion of bulk wires costs shall be collected on the basis of a 12 CP demand charge..... 61
  - The demand portion of local wires costs shall be collected on the basis of an NCP demand charge as determined by billing capacity and utilizing the same ratchet provisions as the current tariff. .... 61
  - The classification of POD costs proposed by the AESO in section 4.3.4 of the Application and as refined by the Board is approved. .... 61
  - The rate design of the POD charge shall collect the customer related portion of costs based on a uniform monthly charge to each POD. The demand related portion of costs shall be collected using the four tier approach as described by the Board in section 5.7.7 of this Decision, with the billing determinant for each POD being based on NCP as determined by billing capacity and utilizing the same ratchet provisions as the current tariff..... 61
23. The Board accepts the evidence of DUC that isolated generation unit customers are already receiving a considerable cross-subsidy from other customers. The Board also agrees with TCE that it would be inappropriate for customers already receiving the benefits of isolated generation service to receive additional benefit through the PSC. The Board rejects the argument of CCA/PICA that the isolated generating units should be eligible because the AESO has not invested in standard facilities. The Board considers that the PSC should only be paid when a customer both avoids AESO investment and genuinely reduces costs to other customers. In the case of the isolated generating units, the customers have not provided their own facilities and no real savings to other AESO customers have been demonstrated. Isolated generation is a substitute for transmission service. The savings related to an isolated generation connection are already captured by the fact that the load is being served by isolated generation, thereby alleviating the need to pay for a transmission line to be built and maintained, and further alleviating the risk of stranded costs. The Board therefore finds that the isolated generating units are not to be eligible for the PSC. .... 68
24. The Board has not approved the AESO's proposed changes to the DTS rate. This appears to alleviate the primary concerns of customers who are concerned with the absence of a specific standby rate. Given the Board's concerns that the proposed standby rate may not accurately reflect the costs that may be imposed on the system by the standby loads, the Board denies approval of the proposed standby rate. While denying this specific proposal, however, the Board acknowledges that a standby rate may be justified at a conceptual level and encourages the parties to continue considering the development of such a rate. .... 72
25. The Board has reviewed the UFLS credits contained in the AESO's rate schedules and agrees that they have not changed from those approved in Decision 2005-096, and further notes that no parties had objected to their continued use. The Board approves the UFLS credits as contained in the AESO's rate schedules. .... 75
26. The Board agrees with the AESO that these rate rider changes generally contain clarifications and corrections. In section 5.9 of in this Decision, the Board has requested that the AESO

- recalculate the impact of the Board approved tariff on the AESO's customers. The Board will therefore not approve the AESO's proposed Rider G at this time, which was designed to mitigate any rate shock related to the AESO's originally rate proposal. With this exception, the Board approves the rate riders as filed..... 75
27. The Board therefore approves the AESO STS rate contained in the STS rate schedule included in section 7 of the Application. .... 76
28. The Board finds that in the context of restoration of interties within the meaning of section 16 of the 2007 *Transmission Regulation*, both the cost of facilities and operational measures on the interties themselves as well as any internal reinforcements within the Alberta transmission system are to be included within the set of costs allocated to rate DTS rather than being specifically identified and allocated to rate XTS. .... 81
29. The Board considers that a rate appropriate for this class of service must be determined with regard for cost allocation principles set out in subsection 27(4). The Board finds that the proposed XTS rate does not comply with subsection 27(4) or subsection 27(6) criterion by virtue of the fact that the different cost sharing principles applicable to intertie path restoration costs and non-restoration intertie project costs are not appropriately reflected in the proposed rate. The Board finds that XTS rate must be denied on this basis. .... 82
30. Secondly, given that additional system costs incurred to accommodate service over a merchant intertie fall within section 27 of the 2007 *Transmission Regulation*, the Board finds that insufficient evidence was offered in this proceeding to allow the Board to determine whether the proposed MTS rate is in compliance with section 27. Accordingly, the Board is unable to approve this rate at this time. .... 91
31. For energy either generated or consumed in Alberta, the Board agrees that customers using a newly constructed merchant intertie would not require the use of the existing Alberta-British Columbia or Alberta-Saskatchewan interties. This indicates that the minimum charge component of the rate (based on the incremental variable cost associated with providing the service) would be equal to or lower than the corresponding XOS rate minimum charge. However, the Board finds that no evidence indicated that the value of the proposed merchant opportunity service (MOS) is less than the value of export opportunity service (XOS). Accordingly, the Board finds that the value of service based rate for MOS 1 Hour and MOS 1 Month is \$3.98/MWh and \$4.36/MWh respectively, consistent with the Board's findings in section 7.2.1. .... 91
32. As a result of feedback obtained during stakeholder consultations, the AESO undertook to revise the investment allowances under the contribution earlier than the 2008 GTA. It is apparent that the AESO encountered obstacles related to the limited amount of available POD cost data in its efforts to gather the data required to fulfill the Board's direction to develop a cost based interconnection project cost function. The Board wishes to acknowledge the AESO's diligence in complying with the Board's direction. The Board confirms that the AESO has complied with the Board's Direction 13A from Decision 2005-096..... 92
33. However, in section 5.7.7 of this Decision, the Board has not approved the POD cost function proposed by the AESO. Accordingly, for greater certainty, the Board confirms that the approved POD cost function set out in section 5.7.7 of this Decision is to be used as the basis for the maximum investment function. The Board discusses the additional steps required to convert the approved POD cost function into the approved maximum investment allowance function. .... 92

34. For all of the above reasons, the Board approves a multiplier of 1.15 to be applied to the cost function approved in section 5.7.7 of this Decision to determine the maximum investment function. .... 98
35. The resulting Board approved maximum investment function is as follows: ..... 98  
 $Y =$  \$1.028 million + \$0.578 million/MW for the first 7.5MW + ..... 98  
 \$0.200 million/MW for the next 9.5MW +  
 \$0.118 million/MW for the next 23MW +  
 \$0.062 million/MW for all MW above 40.0MW
36. The Board disagrees with DUC's view that an additional inflation adjustment is necessary to reflect the anticipated continuation of the 2007 AESO tariff into 2008 and 2009. The maximum investment function set out in section 8.1.2.2 of this Decision is significantly above the maximum investment allowance set out in Decision 2005-096. The Board considers that the increase in the level of the maximum investment allowances, particularly for AESO customers with a large contract capacity, offsets the impact of inflation on the cost of new interconnections. .... 99
37. No parties took issue in argument or reply with these changes as proposed by the AESO. The Board has reviewed Article 9.2, Article 9.7 and Article 9.9 and approves these provisions as filed. .... 99
38. In light of these findings, the Board approves the AESO's standard facilities definition and related T&Cs as initially proposed by the AESO in the Application but *not* the amendments subsequently proposed by the AESO in its supplemental filing. Furthermore, as the issues raised by AE in the current proceeding relate to EUA section 34 processes and not tariff matters, the Board is not prepared to comment on any arrangement or accommodation that may or may not have been reached between the AESO and AE in respect of issues raised by AE in this proceeding..... 103
39. No evidence was submitted in this proceeding of an AESO requirement that a VFD would be required to accommodate motor starting on the distribution system. Based on the evidence in this proceeding, the Board agrees with the AESO, that flicker limits on the distribution system are within the purview of the Discos. The Board considers that the decision to provide transmission or distribution facilities in the circumstances of specific customers must be evaluated separately for customers of the AESO and customers of Discos. Accordingly, the Board will not direct the AESO to amend the interconnection process guidelines. In general, to the extent that PPGA, any specific member thereof, or an end use customer of a Disco, has concerns with technical standards established by a Disco, those concerns should be addressed directly with the Disco and if any irresolvable concerns remain they may be pursued in a relevant Board proceeding relating to the relevant Disco..... 105
40. No objections to these proposed changes were received. The Board accepts the proposed changes as reasonable and they are approved as filed. .... 111
41. Based on the foregoing, the Board finds that an exit fee mechanism is beneficial and economically supportable. Consequently, the Board remains strongly of the view that the continued provision of economic signals through an exit fee mechanism remains a desirable and appropriate aspect of the AESO's tariff. .... 113
42. The Board is not convinced that the reactive power issue raised by EPCOR is a tariff matter. While the AESO's transmission interconnection requirements are defined in Article 1.1 of the AESO's T&Cs, those requirements comprise a number of complex, detailed and technical documents which have been implemented by the AESO pursuant to its rule making authority.

As such, should it be necessary in the future for this matter to be brought before the Board, the Board questions whether it may be more effectively raised outside a tariff proceeding, such as pursuant to the complaint provisions of section 25 of the EUA. The Board also encourages the parties involved to consider using the dispute resolution provisions contained in Article 19 of the T&Cs, if applicable. .... 118

43. Nothing in this Decision shall relieve the AESO of directions arising from the Article 11 Proceeding. Unless otherwise noted in this Decision, the Board considers that the AESO's obligations in respect of directions described in Appendix 5 to this Decision have been fulfilled..... 118
44. To the extent that the interconnection process guidelines are followed, the Board is not persuaded at this time that a direction to the Discos to include provisions mirroring Article 9.1 of the AESO T&Cs is necessary. .... 119
45. In light of the above and in light of the Board's direction in section 5.7.8.3 of the Decision, the Board finds that compliance with Direction 4D is not required at this time. .... 120

**APPENDIX 4 – ABBREVIATIONS**

Abbreviation	Name in Full
A&E	average and excess methodology
AE	ATCO Electric
AESO	Alberta Electric System Operator
ADC	Alberta Direct Connect Consumer Association
AIES	Alberta Interconnected Electric System
AIL	Alberta Internal Load
ASBG/PGA	Alberta Sugar Beet Growers and Potato Growers of Alberta
ATC	Available Transfer Capacity
BRC	budget review committee
CCA	Consumers' Coalition of Alberta
CP	Coincident Peak
CPI	Consumer Price Index
DFO/ Disco	Distribution Facility Owner / Distribution Company
DOS	Demand Opportunity Service
DTS	Demand Transmission Service
DUC	Dual-Use Customers
EPCOR	EPCOR Energy Services Alberta Ltd.
EUA	Electric Utilities Act
FAI	Fortis Alberta Inc.
FTS	Fort Nelson Demand Transmission Service
GRAS	Generator Remedial Action Scheme
GTA	General Tariff Application
IPPCA	Industrial Power Consumers Association of Alberta
IPPSA	Independent Power Producers Society of Alberta
IOS	Import Opportunity Service
ISO	Independent System Operator (AESO)
IPPs	Independent Power Producers
MOS	Merchant Opportunity Service
MTS	Merchant Transmission Service
NARUC	National Association of Regulatory Utility Commissioners
NBV	Net Book Value
NCP	Non-Coincident Peak
NSP	negotiated settlement process
O&M	Operations and Maintenance

OASIS	Open Access Same Time Information System
OM&A	Operations, Maintenance and Administrative
OPP	Operating Policy and Procedure
PICA	Public Institutional Consumers of Alberta
PILON	payments in lieu of notice
POC	Point of connection
POD	Point of delivery
POS	Point of supply
Powerex	Powerex Corp.
PPA	Power Purchase Arrangement
PPGA	Pipeline Power Group and Associates
PSC	Primary Service Credit
RCN	Replacement cost new
RGUCC	Regulated generating unit connection cost
RGU	Regulated generating unit
STS	Supply Transmission Service
TAU	TransAlta Corporation
TCCS	Transmission Cost Causation Study
TCCU	Transmission Cost Causation Update
TCE	TransCanada Energy Ltd.
TFO	Transmission Facility Owner
TMR	Transmission Must Run
T&C	Terms and Conditions of Service
UCA	Utilities Consumer Advocate
UCMD	University of Calgary Math Department
UFLS	Under Frequency Load Shedding
XOS	Export Opportunity Service
XTS	Export Transmission Service

## **APPENDIX 5 – NUMBERING CONVENTION FOR OUTSTANDING BOARD DIRECTIONS**



Appendix 5 to  
Decision 2007-106.dc

(consists of 1 page)

**List of Non-Refiling Related Directions from Decision 2005-096 as Described by AESO in  
Application 1420890**

No	Direction	Decision 2005-096 Section	Page	Proceeding
[1B]	Consider other suggestions of TCE	2.1	3	2007 GTA
2	Remove notionally denied costs or demonstrate prudence	2.2	4	future GTAs
3	True up variances from 2006 placeholder in deferral process	4.1	5	2006 DA
4	Assess business case for AESO-developed forecasts	4.2.1	7	2007 GTA
[4A]	Explain the basis of forecasts relied on in GTAs	4.2.1	7	future GTAs
[4C]	Conduct more thorough review of bulk system lines	5.3.2	23	future study
[4D]	Address TFO O&M costs that may be energy related	5.3.2	23	future study
[12A]	Evaluate minimum service norms for DISCOs	6.1.3	55	2007 GTA
[13A]	Conduct further study for investment function proposal	6.1.4	58	2008 GTA
[20A]	Conduct further analysis on appropriate prepaid O&M rate	6.1.6.7	69	2008 GTA
22	Harmonize DISCO and AESO contribution policies	6.3.2	73	2007 GTA
24	Address merchant interconnection principles	7.4	80	2007 GTA
[29A]	Include, in all GTAs, revenue requirement and revenue offset amounts for two prior years and the test year, with variance explanations	8.1	89	On- going
[29B]	Include, in all GTAs, a management discussion section and a cost breakout for two prior year actuals, current year projection, and test year forecast, with variance explanations	8.1	89	On- going
[29C]	Include, in all GTAs, insurance cover notes	8.1	89	On- going
[29D]	Report all amounts received from generators under an LBC SO as an offset to forecast revenue requirement	8.1	89-90	On- going
[29E]	File annually the number of times conscripted ancillary services were procured and the costs, and include a forecast of such cost in all GTAs	8.1	90	On- going
[29F]	Report, in all GTAs for the term of LBC SO contracts, any occurrences where the generator exceeded the maximum time to commercial operations	8.1	90	On- going
[29G]	Deal with Proxy Unit directions in the Ancillary Services Article Amendment proceeding	8.1	90	AS Art