

IN THE MATTER OF the Alberta Electric System Operator (“AESO”) tariff and rates approved by the Alberta Utilities Commission (“AUC”) pursuant to sections 30 and 119 of the Electric Utilities Act S.A. 2003 c.E-5.1.

IN THE MATTER OF Alberta Energy and Utilities Board (“EUB”) Decision 2007-106 and Directions made thereto.

**Alberta Electric System Operator
2007 General Tariff Application
Refiling**

February 1, 2008

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1 APPLICATION

5 On December 21, 2007, the Alberta Energy and Utilities Board (EUB) issued Decision 2007-106 with respect to the 2007 General Tariff Application (GTA) of the Alberta Electric System Operator (AESO). The AESO had filed its 2007 GTA on November 3, 2006. The application requested approval of forecast revenue requirements for 2007, and approval of both new rate schedules and changes to the terms and conditions of system access service.

10 Decision 2007-106 provided various directions to the AESO with respect to the application, and concluded on page 121 as follows:

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

- 15 (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.*

20 This refiling is in response to the order of the EUB in Decision 2007-106, and complies with all directions in that decision which were to be addressed in the refiling. The AESO notes that some directions in the decision are to be addressed in the AESO's next GTA, and these accordingly are not addressed in this refiling.

25 This refiling is organized into the following sections:

- 1 Application
2 Matters Addressed in Refiling
3 Summary of Directions
4 Responses to Directions
30 5 Rate Calculations
6 Proposed Tariff
- A Appendix: Blackline Version of Refiled 2007 Tariff
B Appendix: Bill Impact Analysis

35 1.1 Relief Requested

Based on the foregoing, the AESO requests:

- 40 (a) Approval of its 2007 forecast revenue requirement amounts as refiled, comprising wire costs, ancillary services costs, transmission line losses, and AESO own costs;
- (b) Approval of rate schedules and terms and conditions of system access service, both
45 as refiled; and
- (c) Such other relief as the AUC deems appropriate.



All of which is respectfully submitted this 1st day of February, 2008.

Alberta Electric System Operator

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Per: _____
Heidi Kirrmaier
Vice-President Regulatory

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2 MATTERS ADDRESSED IN REILING

This refiling comprehensively addresses all matters in Decision 2007-106 which were required to be addressed at this time.

Some corrections to the proposed tariff were identified in AESO Errata Filing No. 2 dated May 10, 2007. Those corrections have also been included in this refiling.

The tariff included in this refiling included the 2008 Balancing Pool Consumer Allocation Rider F, as approved by the EUB in Order U2007-209 on November 16, 2007, to be effective January 1, 2008.

2.1 Rates and Terms and Conditions Removed in This Refiling

In Decision 2007-106, the EUB denied or otherwise did not approve certain rates and terms and conditions proposed by the AESO in its 2007 General Tariff Application. As these rates and terms and conditions do not appear in the AESO's current tariff, there were no specific directions associated with some of them. For the benefit of participants in this proceeding, the AESO lists below those rates and terms and conditions which have been removed from this refiling and which are not addressed in the AESO's responses to directions in section 4 of this refiling, with associated references to Decision 2007-106.

- (a) **Proposed Rate XTS** — “The Board finds that XTS rate must be denied on this basis.” [p. 82] References to Rate XTS have been removed from other rate and rider schedules, and in the proforma system access service agreements provided in Terms and Conditions Appendix B.
- (b) **Proposed Rate MTS** — “Accordingly, the Board is unable to approve this rate at this time.” [p. 91] References to Rate MTS have been removed from other rate and rider schedules, and in the proforma system access service agreements provided in Terms and Conditions Appendix B.
- (c) **Proposed Rates MOS 1 Hour and MOS 1 Month** — “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 Boards findings in section 7.2.1.” [p. 91]

As the EUB has found that the charges under Rates MOS 1 Hour and MOS 1 Month are to be the same as the charges under Rates XOS 1 Hour and XOS 1 Month, there is no longer any reason to differentiate between the MOS and XOS rates. The AESO has therefore deleted Rates MOS 1 Hour and MOS 1 Month from the tariff included in section 6 of this refiling, including references to those rates in other rate and rider schedules. Instead, the Alberta-Montana Intertie is now included as one of the points of interconnection available under the system access service agreement for export opportunity service, as indicated on the *proforma* agreement in Terms and



Conditions Appendix B of the tariff in section 6 of this refiling. Specific agreements for the Montana-Alberta intertie are no longer provided in Appendix B.

2.3 Other Revisions

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The AESO has updated the defined term “Transmission Regulation” in Article 1 of the Terms and Conditions in section 6 of this refiling, to refer to the 2007 *Transmission Regulation* as enacted on April 11, 2007. References within the tariff to section numbers in the *Transmission Regulation* have also been revised to reflect the numbering of section in the 2007 *Transmission Regulation*.

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The AESO has similarly updated the defined term “Affiliate” to refer to a more recent version of the Business Corporations Act:

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References to the Alberta Energy and Utilities Board or EUB have been changed to the Alberta Utilities Commission or AUC throughout the proposed tariff.

20

The AESO has corrected an incorrect reference to “Customer Commitment Agreement” in Article 6.2 of the proposed tariff. The article has been revised to refer to the defined term “Construction Commitment Agreement”.

25

Typographical errors, formatting inconsistencies, and similar minor errors have been corrected in the tariff in section 6 of this refiling.

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Finally, the AESO notes that it has filed Application No. 1549401 requesting approval of a revised Article 11 developed through a negotiated settlement process. Article 11 as included in the terms and conditions in this refiling will be updated as necessary at such time as the AUC approves the Article 11 application.

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3 SUMMARY OF DIRECTIONS

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This section provides a summary table of all directions included in this refiling, whether included in the Appendix 2 Summary or in the text of Decision 2007-106. The summary table indicates whether the direction has been responded to in this refiling or will be responded to in the AESO's next GTA.

No	Direction	Sec	Pg	Refiling	Other
[0]	Reflect new provisions of 2007 <i>Transmission Regulation</i>	2	6	✓	
1	Update TFO costs for interim or final approvals	3.1	11	✓	
2	Propose additional cost causation refinements if warranted	5.3.1	25		next GTA
3	Continue wires cost unbundling and bulk CP demand billing	5.5.1	35	✓	
4	Continue local system NCP demand billing, including ratchet	5.5.2	35	✓	
5	Reflect approved linear POD cost function	5.7.7	55	✓	
6	Assess cost and time to study TFO O&M cost causation	5.7.8.3	59	✓	
7	Reflect findings and directions with respect to DTS rate	5.8	61	✓	
8	Consider rate impact to be unlikely	5.9	62	✓	
9	Prepare bill impact analysis	5.9	63	✓	
10	Adjust Primary Service Credit	5.10.1	66	✓	
11	Amend PSC eligibility to exclude isolated communities	5.10.2	68	✓	
12	Update DOS 7 Minutes rate to reflect approved DTS rate	6.1	74	✓	
13	Propose new DOS 1 Hour and DOS Term rates	6.1	74	✓	
14	Amend Rate FTS to align with Rate DTS	6.2	75	✓	
15	Identify export rates not offered until OASIS is complete	7.1.2	83	✓	
16	Adjust XOS charges in accordance with TCE Figure 4	7.2.1	87	✓	
17	Implement Rate IOS as filed	7.2.2	87	✓	
[17A]	Implement approved maximum investment function	8.1.2.2	98	✓	
18	Conduct a study of incremental TFO O&M	8.3	106		next GTA
19	Remove "prepaid" from Operations and Maintenance Article 9.4	8.3	107	✓	

Note: Direction numbers in square brackets (such as [0]) indicate directions which were not included in the Appendix 2 Summary of Board Directions in Decision 2007-106.



No	Direction	Sec	Pg	Refiling	Other
20	Conduct further analysis on staged contributions	8.4	111		next GTA
21	Revised RGUCC-related provisions in Article 14.6	8.7	116	✓	
22	Revise Peak Metered Demand Waiver Article 16	8.8	117	✓	
23	Provide an update with respect to EnCana Countess facility	9.4	121	✓	

Note: Direction numbers in square brackets (such as [0]) indicate directions which were not included in the Appendix 2 Summary of Board Directions in Decision 2007-106.

0 Reflect New Provisions of 2007 *Transmission Regulation*

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Direction

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. [p. 6]

Response

The only material change to subsection 29(4) of the 2007 *Transmission Regulation*, compared to subsection 17(4) of the 2004 *Transmission Regulation*, appears in clause (a):

Generating unit owner's contribution

29(4) *The ISO tariff must include terms and conditions providing for the following:*

- (a) *the refund of money paid under this section, to the owner who paid it, over a period of not more than 10 years **from the date the generating unit begins to generate electric energy for the purpose of exchange but not for the purpose of testing or commissioning the unit**, subject to satisfactory operation of the generating unit determined under rules made under subsection (5), where satisfactory operation may vary by generation type; (emphasis added)*

Changes to section 30 of the 2007 *Transmission Regulation*, compared to section 18 of the 2004 *Transmission Regulation*, are as follows:

Non-application of sections 28 and 29

30 *Sections 28 and 29 do not apply to a generating unit connected to the transmission system **before January 1, 2006 or to a generating unit that has a capacity of 1 MW or less.** (emphasis added)*

The AESO has revised Articles 9.11 and 9.12 of the terms and conditions of service included in section 6 of this refiling, to reflect the provisions of the 2007 *Transmission Regulation* quoted above.

Clause 29(4)(a) of the 2007 *Transmission Regulation* removes the requirement of the AESO to monitor a planned commercial operation date, and focuses the beginning of the refund period on the actual commercial operation date. Article 1.1 of the AESO terms and conditions provide the following definition:

“Commercial Operation” means the date upon which a load or Generating Unit begins to operate on the transmission system in a manner which is acceptable to the AESO and which is expected to be normal for it to so operate, after energization and Commissioning.

Clause 29(4)(a) requirements can be accommodated through changes to Articles 9.12(b) and (c) of the terms and conditions, and through the deletion of existing Article 9.12(d), as follows (changes in bold):

9.12 **Refund of System Contribution**

- (a) A Customer’s System Contribution will be refunded to the Customer if the Customer’s generating unit meets the ISO Rules regarding satisfactory annual performance, in accordance with the provisions of this Article 9.12.
- (b) The System Contribution will be refunded in annual amounts **during the “Refund Period”. The Refund Period begins on January 1 following the Commercial Operation date of the Customer’s generating unit and ends nine calendar years later on December 31.**
- (c) **The annual amounts during the Refund Period will be:**
 - (i) **5.6% of the System Contribution in each of the first through fourth calendar years in the Refund Period;**
 - (ii) **11.2% of the System Contribution in the fifth calendar year in the Refund Period; and**
 - (iii) **16.6% of the System Contribution in each of the sixth through ninth calendar years in the Refund Period.**
- (d) For each calendar year **during the Refund Period** in which the ISO Rules regarding satisfactory annual performance are met, the Customer will receive a refund of the annual amount determined in (c) for that year. If the ISO Rules regarding satisfactory annual performance are not met, the annual amount for that year will be forfeited.
- (e) For each year of the Refund Period, the Customer must report the unit’s annual performance to the AESO by January 31 of the following year.
- (f) For each year of the Refund Period where the Customer has reported annual performance and where the ISO Rules regarding satisfactory annual performance are met, the AESO will pay the System Contribution refund annual amount to the Customer by February 28 of the following year.

To illustrate the application of revised Article 9.12, the AESO provides examples on the next page which indicate the refund of a System Contribution of \$1,000,000 to three different generators. In the table, a status of “on” indicates the generator met the ISO Rules regarding satisfactory annual performance, and a status of “off” indicates the generator did not meet the ISO rules.

Generator A pays the System Contribution on July 1, 2008, prior to construction, and has a Commercial Operation date (COD) of July 1, 2009. The generator maintains satisfactory annual performance over the next nine years, and accordingly receives a full refund of the System Contribution over those nine years.

Generator B also pays the System Contribution on July 1, 2008, prior to construction, but has a later Commercial Operation date of July 1, 2011. The generator also maintains satisfactory annual performance over the next nine years, and accordingly receives a full refund of the System Contribution over those nine years.

Generator C pays the System Contribution on July 1, 2008, prior to construction, and has a Commercial Operation date of July 1, 2009. However, the generator does not meet the ISO Rules for satisfactory annual performance in 2013 and 2014, and accordingly forfeits the \$56,000 and \$112,000 refunds which would otherwise have been received in those years.

Table D0 Illustrative Examples of Refunds of \$1,000,000 System Contributions

		Generator A		Generator B		Generator C	
Contribution		Jul 1, 2008		Jul 1, 2008		Jul 1, 2008	
COD		Jul 1, 2009		Jul 1, 2011		Jul 1, 2009	
Year	Status	Refund	Status	Refund	Status	Refund	
2008	pre-COD	NA	pre-COD	NA	pre-COD	NA	
2009	pre-COD	NA	pre-COD	NA	pre-COD	NA	
2010	On	\$56,000	pre-COD	NA	On	\$56,000	
2011	On	\$56,000	pre-COD	NA	On	\$56,000	
2012	On	\$56,000	On	\$56,000	On	\$56,000	
2013	On	\$56,000	On	\$56,000	Off	\$0	
2014	On	\$112,000	On	\$56,000	Off	\$0	
2015	On	\$166,000	On	\$56,000	On	\$166,000	
2016	On	\$166,000	On	\$112,000	On	\$166,000	
2017	On	\$166,000	On	\$166,000	On	\$166,000	
2018	On	\$166,000	On	\$166,000	On	\$166,000	
2019	NA	NA	On	\$166,000	NA	NA	
2020	NA	NA	On	\$166,000	NA	NA	
Total		\$1,000,000		\$1,000,000		\$832,000	

Section 30 of the 2007 *Transmission Regulation* specifies a date before which the system contribution provisions do not apply, and also specifies a minimum capacity below which they do not apply. Section 30 requirements can be accommodated through changes to Articles 9.11(c) of the terms and conditions, as follows (changes in bold):

9.11 **Determination of System Contribution**

...

- (c) System Contributions are not required for STS Capacity requirements for which a System Access Service Agreement was signed before January 1, 2006, **or for STS Capacity requirements of 1 MW or less.**

References within the terms and conditions of service to specific sections of the *Transmission Regulation* have also been updated to refer to the 2007 *Transmission Regulation*, as has the definition of *Transmission Regulation* itself.

1 Update TFO Costs for Interim or Final Approvals

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Direction

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. [p. 11]

Response

The AESO has updated its wires-related costs forecast to reflect interim and final approvals of 2007 TFO tariffs that have occurred since the 2007 tariff application was filed on November 3, 2006. The TFO tariff amounts included in this refiling are provided in the table below, together with the corresponding amounts included in the AESO's GTA.

Transmission Facility Owner	2007 Refiling \$ 000 000	2007 GTA \$ 000 000	EUB Decision Reference
AltaLink	\$208.0	\$193.7	Decision 2007-050 (Jun 19, 2007) 2007 Final TFO Tariff
ATCO Electric Ltd. Isolated Generation Subtotal ATCO Costs	\$169.5 <u>(\$ 7.9)</u> \$161.6	\$166.4 <u>(\$ 7.9)</u> \$158.5	Decision 2007-104 (Dec 21, 2007) 2007 Final TFO Tariff
ENMAX Power Corporation	\$ 31.9	\$ 34.7	Decision 2006-130 (Dec 21, 2006) 2007 Interim TFO Tariff
EPCOR Transmission	\$ 36.8	\$ 38.1	Order U2006-315 (Dec 15, 2006) 2007 Interim TFO Tariff
City of Lethbridge	\$ 4.4	\$ 4.4	Order U2006-47 (Feb 24, 2006) 2007 Final TFO Tariff
TransAlta	\$ 4.2	\$ 3.7	Decision 2007-050 (Jun 19, 2007) 2007 Final TFO Tariff
City of Red Deer	\$ 1.7	\$ 1.7	Order U2006-48 (Feb 24, 2006) 2007 Final TFO Tariff
FortisAlberta (Farm Transmission Costs)	\$ 1.5	\$ 1.9	Decision 2006-099 (Oct 16, 2006) (2007 Final Costs)
TFO Wires-Related Costs	\$450.0	\$436.7	

Note: Numbers may not add due to rounding.

Accordingly, TFO wires-related costs totalling \$450.0 million have been included in Schedule 2.0 in the rate calculations in Section 5 of this refiling.

2 Propose Additional Cost Causation Refinements if Warranted Page 1 of 1

Direction

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. [p. 25]

Response

The AESO will present, in its next GTA, a comparison of the value and cost of additional refinements to the transmission cost causation study, and will propose any refinements that it considers warranted at that time. As suggested in the AESO's response to Direction 6 on assessing the cost and time to study TFO O&M cost causation, it may be efficient to respond to Direction 2 as part of the study required by Direction 6.

3 Continue Wires Cost Unbundling and Bulk CP Demand Billing Page 1 of 1

Direction

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. [p. 35]

Response

As in the current tariff, the AESO has continued the unbundling of bulk system and local system costs in the rate calculations in section 5 of this application, and in the Demand Transmission Service and Fort Nelson Transmission Service rate schedules in the tariff in section 6 of this application.

Also as in the current Rate DTS, the demand component of bulk system costs continues to be collected through the 12 CP method using monthly coincident metered demand.



4 Continue Local System NCP Demand Billing, Including Ratchet Page 1 of 1

Direction

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. [p. 35]

Response

As in the current Rate DTS, the demand component of local system costs continues to be collected based on NCP using billing capacity, which is the greatest of the highest metered demand in the billing period, 90% of contract capacity, or 90% of the peak demand in the prior 24 months.

5 Reflect Approved Linear POD Cost Function

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Direction

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

$$Y = \$0.894 \text{ million} + \$0.503 \text{ million/MW for the first 7.5 MW} + \\ \$0.174 \text{ million/MW for the next 9.5 MW} + \\ \$0.102 \text{ million/MW for the next 23 MW} + \\ \$0.054 \text{ million/MW for all MW above 40.0 MW. [p. 55]}$$

Response

The approved linear POD cost function as provided above is used in the rate calculations (on Schedule 5.4 in section 5) and in the maximum investment function (as discussed in response to Direction 17A) in this refiling.

6 Assess Cost and Time to Study TFO O&M Cost Causation

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Direction

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. [p. 59]

Response

The AESO has reviewed with PS Technologies the cost and time required to prepare a further study into the causation of TFO O&M costs. The AESO estimates that such a study would likely require eight months of calendar time to complete and would be expected to incur on the order of \$100,000 in AESO and consultant costs. The study would result in recommendations for the functionalization and classification of TFO O&M costs for use in the AESO's DTS rate design, and would include stakeholder consultation. The estimate does not include time or costs related to any regulatory proceeding in which the study or implementation of its results is reviewed.

The estimate also does not include any costs that may be incurred by a TFO in providing information in support of the study. The AESO expects that the study will require significant amounts of information from the TFOs, beyond what is normally provided to external parties. The AESO requests that the AUC confirm that any unforecast costs incurred by TFOs in providing such information is a recoverable expense for the TFOs, either through direct billing to the AESO or through inclusion in a deferral account.

The AESO also suggests it may be efficient to respond to Directions 2 (to propose additional cost causation refinements if warranted) and 18 (to conduct a study of incremental TFO O&M costs) as part of the study of TFO O&M cost causation.

7 Reflect Findings and Directions With Respect to DTS Rate

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Direction

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. [p. 61]

Response

This refiling reflects the findings and directions summarized above, as described below with references to the rate calculation schedules in section 5.

- (a) Transmission costs have been functionalized as illustrated in section 4.3.5 of the Application, as provided in Schedule 5.1.
- (b) Bulk system costs and local system costs have been classified 82% as demand-related and 18% as energy-related in Schedule 5.3.
- (c) The 18% of bulk system costs and 18% of local system costs which are classified as energy-related are collected on the basis of an all hours flat usage charge in Schedules 5.5 and 5.6, and as reflected in Rate DTS in section 6 of this refiling.
- (d) The 82% of bulk system costs which are classified as demand-related are collected on the basis of a 12 CP coincident metered demand charge in Schedules 5.5 and 5.6, and as reflected in Rate DTS in section 6 of this refiling.

- (e) The 82% of local system costs which are classified as demand-related are collected on the basis of an NCP billing capacity demand charge in Schedules 5.5 and 5.6, and as reflected in Rate DTS in section 6 of this refiling with the same ratchet provisions as the current Rate DTS.
- (f) POD costs have been classified as proposed by the AESO in section 4.3.4 of the Application and as refined by the EUB, as provided in Schedule 5.4.
- (g) The POD charge has been designed to collect customer-related costs through a uniform monthly charge and demand-related costs on the basis of billing capacity using the four-tier approach described by the EUB, as provided in Schedules 5.4, 5.5, and 5.6. This charge is also reflected in Rate DTS in section 6 of this refiling with the same ratchet provisions as the current Rate DTS.

The AESO notes that, in the POD charge developed in response to this direction, the substation fraction continues to apply to the customer (\$/month) component and not to any of the demand (\$/MW) components of the charge. This is consistent with the POD charge in the current DTS rate, but differs from the POD charge proposed in the AESO's GTA where the substation fraction applied to both the customer component and the first (7.5 MW) demand component.

In a letter dated October 21, 2005, in the AESO 2005-2006 GTA, the EUB clarified that "its intent was that the new customer charge component of the DTS rate ordered in Direction 6 [of Decision 2005-096] would be apportioned amongst the customers served by a particular POD rather than applied in full to each customer served by that POD." The AESO accordingly implemented that intent by multiplying the customer charge by the substation fraction at each POD.

In the AESO's 2007 GTA, the AESO considered that "the customer and first demand components of the [proposed] cost function can be considered representative of the fixed cost of multiple-service substations" (AESO 2007 GTA, section 4, page 21). The same approach was assumed in the AESO's responses to information requests submitted on November 19, 2007, as part of the comment process on the EUB's proposed approach to the construct of the POD cost function.

However, Direction 5 of Decision 2007-106 requires the AESO to implement a POD cost function that is significantly different from that proposed in the AESO's GTA. That POD cost function is based on a continuous power curve, reflective of significant economies of scale with increasing capacity, and considered "more robust and desirable" by the EUB (Decision 2007-106, page 51). The customer (fixed) component of the directed cost function is \$0.894 million, and consistent with the clarification provided in the EUB's letter in the AESO's 2005-2006 GTA, the AESO has apportioned that customer component (and no demand components) amongst the customers served by a particular substation through the application of the substation fraction.

8 Consider Rate Impact to be Unlikely

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Direction

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. [p. 62]

Response

Direction 8 above explains that the EUB considers the directed changes to the AESO's cost allocation and rate design are unlikely to result in rate impacts to a significant number of PODs. The EUB further notes in section 6.4 of Decision 2007-107 (page 75), "In section 5.9 of...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."

The AESO has therefore removed the proposed Bill Impact Mitigation Rider G from this refiling.

9 Prepare Bill Impact Analysis

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Direction

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. [p. 63]

Response

The requested bill impact analysis is included as Appendix B to this refiling.

Appendix B contains the following schedules:

- B-1 Summary of Average Per-POD Bill Impacts for DTS Charges and Commodity
- B-2 Distribution of Per-POD Bill Impacts for DTS Charges and Commodity
- B-3 Per-POD Bill Impacts for DTS Charges and Commodity
- B-4 Per-POD DTS and Commodity Bill Components
- B-5 Per-POD DTS and Commodity Bill Component Increases, 2005 to 2007
- B-6 Per-POD DTS and Commodity Bill Component Increases, 2005 to 2006
- B-7 Per-POD DTS and Commodity Bill Component Increases, 2006 to 2007
- B-8 Per-POD Bill Impacts for DTS Charges and Commodity Where Increase Is Greater Than 10%
- B-9 Summary of average per-POD Bill Impacts for DTS Charges and Commodity Where Increase Is Greater Than 10%
- B-10 Abbreviations Used in Schedules

Schedules B-1 through B-7 provide information in the same format as provided in response to Information Request BR.AESO-003 Revised, dated February 26, 2007. Schedules B-8 and B-9 provide additional detail on PODs receiving an increase of greater than 10% in comparison to the 2006 tariff. Schedule B-10 provides the meaning of abbreviations and terminology used in the other schedules.

In preparing Appendix B, the AESO used an updated extract of actual customer billing determinants from January 2006 through December 2007. The AESO considers that the updated billing determinants provide a more accurate representation of actual customer bills, as all the billing determinants used in the current and proposed DTS rates (including coincident metered demand and substation fraction) are available for the full two years.

The updated billing determinants also resulted in four additional PODs being included in the bill impact analysis, compared to the PODs included in BR.AESO-003 Revised. With the updated billing determinants, twelve months of billing data were now available for those PODs and they were accordingly incorporated into the analysis. PODs with less than 12 months of billing data have been excluded from the analysis.

With the updated billing determinants and the inclusion of additional PODs, the data has been resorted by billing capacity and the POD order has changed. That is, a POD identified by POD number in the information provided in BR.AESO-003 Revised will likely have a different POD number in Appendix B. This avoids concerns regarding the ready identification of the new PODs.

The calculations are based on the actual billing determinants for each POD, including the actual pool price for metered energy at the POD. The different DTS rates have been applied to the same billing determinants, including pool price, at each POD. This should isolate the increases attributable to DTS rate changes only.

Although actual pool price for metered energy has been used at each POD, the AESO notes that DTS customers can make individual arrangements for commodity purchases which are not visible to the AESO and which may not be reflective of pool price. Actual pool price may therefore not be representative of the price paid by such customers for their commodity purchases.

The bill impact analysis presented in Appendix B is an estimate of the impact of the different DTS rates on customers. Bills for an individual DTS POD will vary from these estimates depending on actual demand and usage at the POD, including variations in hourly pool price.

10 Adjust Primary Service Credit

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Direction

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.

[p. 66]

Response

The Primary Service Credit directed by the EUB as described above is summarized in the following table

Rate Component	DTS Charge	Primary Service Credit	
	Amount	%	Amount
Billing Capacity Charge ≤7.5 MW	\$3,090.00/MW	55%	\$1,700.00/MW
Bill Cap Charge >7.5 to ≤17 MW	\$1,069.00/MW	55%	\$588.00/MW
Bill Cap Charge >17 to ≤40 MW	\$627.00/MW	55%	\$345.00/MW
Billing Capacity Charge >40 MW	\$332.00/MW	100%	\$332.00/MW
Customer Charge	\$5,493.00/month	55%	\$3,021.00/month

The Primary Service Credit amounts determined in the table are reflected in Rate PSC in section 6 of this refiling.

The PSC rate schedule notes, “The Primary Service Credit is provided in conjunction with a reduced maximum Local Investment in accordance with the Terms and Conditions of Service.” The reduced PSC investment is determined using corresponding percentage reductions to the maximum investment function described on page 98 of Decision 2007-106, as follows:

Investment Function Component	DTS Investment	PSC Investment	
	Amount	%	Amount
Fixed	\$51,400/year	45%	\$23,130/year
First 7.5 MW of Contract Capacity	\$28,900/MW/year	45%	\$13,005/MW/year
Next 9.5 MW of Contract Capacity	\$10,000/MW/year	45%	\$4,500/MW/year
Next 23 MW of Contract Capacity	\$5,900/MW/year	45%	\$2,655/MW/year
All Remaining Contract Capacity	\$3,100/MW/year	0%	\$0/MW/year

The reduced maximum Local Investment for services receiving the PSC is provided in Article 9.6(a)(ii) of the Terms and Conditions of Service in section 6 of this refiling.

11 Amend PSC Eligibility to Exclude Isolated Communities

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Direction

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. [p. 68]

Response

The direction states that the Primary Service Credit is to be restricted to "dual use customers and those unconventional interconnection described by the AESO" and not provided to isolated generating units. The direction does not specifically address load-only services where customers provide their own conventional transformation facilities. However, some load-only services include customer-owned transformation, such as at the Express Hardisty and Exshaw substations identified in the AESO's response to Information Request CG.AESO-017 (b).

In the discussion preceding the direction, the EUB comments, "The Board considers that the PSC should only be paid when a customer both avoids AESO investment and genuinely reduces costs to other customers." Load-only services where customers provide their own conventional transformation facilities would generally satisfy this consideration similar to dual-use customers. It is likely the EUB's terminology simply reflected an imprecise heading on Schedule CG.AESO-017 (b-c) provided in the information response.

The AESO has therefore amended the PSC Rate to restrict eligibility for the PSC to customers who purchase, own, and operate their own transformation facilities and to unconventional interconnections, and to specifically exclude isolated communities. The eligibility provisions in the PSC Rate in section 6 of this refiling are as follows.

- Available to: DTS Customers supplied under suitable long term contract who:
- have purchased, own, and operate their own transformation facilities to step the voltage down from transmission voltage to 25 kV or less, and associated low-voltage facilities; or
 - are served through unconventional interconnections such as those using metering transformers.

The Primary Service Credit is not available for service to an isolated community as defined under the *Isolated Generating Units and Customer Choice Regulation*, A.R. 165/2003, as amended from time to time.

12 Update DOS 7 Minutes Rate to Reflect Approved DTS Rate

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Direction

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%. [p. 74]

Response

The AESO's 2007 DTS revenue requirement, updated for interim or final approvals of TFO costs as required by Direction 1 and converted into \$/MWh amounts in accordance with the approvals summarized in Direction 7, is provided in Schedule 5.9 in section 5 of this refiling. That Schedule provides the following amounts:

DTS Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	\$ 3.03	\$ 0.66	\$ 3.69
Interconnection – Local System	1.26	0.28	1.54
Interconnection – POD	3.61	-	3.61
Operating Reserve	-	2.29	2.29
Voltage Control	-	0.93	0.93
Other System Support	0.14	-	0.14
Total	\$8.05	\$4.16	\$12.21

The variable cost components attributable to the DOS 7 Minutes rate (consistent with the approach described in section 4.7 of the AESO's 2007 General Tariff Application) is also provided in Schedule 5.9 and summarized below.

DOS 7 Minutes Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	-	\$ 0.66	\$ 0.66
Interconnection – Local System	-	0.28	0.28
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	-	\$ 3.23	\$ 3.23

The updated DOS 7 Minutes charge, based solely on variable costs with no contribution to fixed costs, is \$3.23/MWh, which represents an increase of \$0.23/MWh or about 8% compared to the existing DOS 7 Minutes charge. This increase is greater than the overall DTS rate increase of 0.7% calculated in Line 16 of Schedule 5.11 in section 5 of this refiling, and therefore exceeds the possible basis for setting the level for DOS 7 Minutes as suggested in the Direction.

The AESO therefore proposes no contribution to fixed costs be included in the DOS 7 Minutes rate. The AESO considers this appropriate for an opportunity rate with lowest curtailment priority and shortest notice time, compared to other services available from the AESO. The AESO also notes that any contribution to fixed costs would add to an increase which is already greater than the overall DTS rate increase.

A charge of \$3.23/MWh is therefore included in the DOS 7 Minutes rate schedule in section 6 of this refiling.

13 Propose New DOS 1 Hour and DOS Term Rates

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Direction

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. [p. 74]

Response

As discussed in response to Direction 12, the AESO's updated 2007 DTS revenue requirement, converted into \$/MWh amounts, is provided in Schedule 5.9 in section 5 of this refiling and summarized below:

DTS Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	\$ 3.03	\$ 0.66	\$ 3.69
Interconnection – Local System	1.26	0.28	1.54
Interconnection – POD	3.61	-	3.61
Operating Reserve	-	2.29	2.29
Voltage Control	-	0.93	0.93
Other System Support	0.14	-	0.14
Total	\$8.05	\$4.16	\$12.21

(a) **DOS 1 Hour Rate**

In response to Direction 12, the AESO considered no contribution to fixed costs was appropriate for the DOS 7 Minutes rate.

In section 4.7 of the AESO's 2007 General Tariff Application, the AESO proposed the DOS 1 Hour rate include a small contribution to fixed costs, determined as 50% of the \$/MWh amounts associated with the DTS bulk system and local system fixed components. A small amount is appropriate because DOS 1 Hour loads would be curtailed with somewhat longer notice than DOS 7 Minutes loads.

The fixed and variable cost components attributable to the DOS 1 Hour rate, including a contribution of 50% of the \$/MWh amounts associated with the DTS bulk system and local system fixed components, is provided in Schedule 5.9 and summarized in the following table.

DOS 1 Hour Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	\$ 1.51	\$ 0.66	\$ 2.18
Interconnection – Local System	0.63	0.28	0.91
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	\$ 2.14	\$ 3.23	\$ 5.37

The proposed DOS 1 Hour charge, based on variable costs with a contribution to fixed costs as described above, is \$5.38/MWh, which represents an increase of \$0.38/MWh or about 7% compared to the existing DOS 1 Hour charge. This increase is comparable to the increase in the DOS 7 Minutes charge provided in response to Direction 12, and is considered appropriate by the AESO.

A charge of \$5.37/MWh is therefore included in the DOS 1 Hour rate schedule in section 6 of this refiling.

(b) **DOS Term Rate**

In section 4.7 of the AESO's 2007 General Tariff Application, the AESO proposed the DOS Term rate include a contribution to fixed costs that converted annual ratchet-related system charges incurred by loads above contract capacity into a \$/MWh amount. Direction 3 of Decision 2007-106 unbundles bulk system and local system costs, and requires the recovery of bulk system costs on a coincident peak basis which would not incur ratchet-related charges. In addition, Direction 4 requires the recovery of local system costs on a non-coincident peak basis with ratchet provisions.

With respect to bulk system costs, the AESO proposes that the DOS Term rate include a contribution of 100% of the \$/MWh amounts associated with the DTS bulk system fixed component.

With respect to local system costs, the AESO proposed that the DOS Term rate include a contribution that provides revenue equivalent to the annual ratchet provisions included in the billing capacity determinant on which the DTS local system charge is based. A 1 MW excursion above contract capacity would incur (1 MW × 1 month) + (1 MW × 90% × 11 months) = 10.9 MW-months of charges. The revenue recovery would be based on a typical four week period (28 days × 24 hours/day = 672 hours) for annual maintenance of a generator. The local system fixed cost contribution would be calculated as follows:

$$\$579.00/\text{MW}/\text{month} \times 10.9 \text{ MW-months} = \$6,311.10$$

$$\$6,311.10 \div 672 \text{ MWh} = \$9.39/\text{MWh}$$

Summing the total variable cost of \$3.23/MWh, the bulk system fixed cost contribution of \$3.03/MWh, and the local system fixed contribution of \$9.39/MWh results in a cost of \$15.65/MWh. This represents a decrease of \$4.35/MWh or about 22% compared to the existing DOS Term charge. The AESO considers such a decrease to be inappropriate when other DOS rates are receiving increases. In addition, the DOS Term qualifying criteria are being relaxed to allow the use of DOS Term (and only DOS Term) for increased electrical consumption during planned maintenance of an on-site generator.

Specifically, the AESO proposed to remove the requirement that a customer must make a convincing case that load would be reduced to avoid ratchet charges on the DTS rate if DOS Term could not be used for generator maintenance, as assessing such a case has always been problematic for the AESO. This change in qualifying criteria was discussed in section 4.7 of the AESO's Application, but was not explicitly commented on in Decision 2007-106.

The AESO considers that a larger contribution to fixed costs than the minimum amount discussed above is appropriate, to ensure customers are not enticed to use DOS Term as a replacement for DTS for extended periods of time. The AESO suggests an appropriate contribution would result in the DOS Term charge being increased by an amount comparable to the increases to the DOS 7 Minutes and DOS 1 Hour rates, namely 8%. The AESO accordingly proposes the local system contribution to fixed costs for DOS Term be set at \$15.34/MWh, such that the total DOS Term charge is \$21.60/MWh as summarized below.

DOS Term Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	\$ 3.03	\$ 0.66	\$ 3.69
Interconnection – Local System	15.34	0.28	15.62
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	\$18.37	\$ 3.23	\$21.60

The proposed DOS Term charge, based on variable costs with a contribution to fixed costs as described above, is \$21.60/MWh, which represents an increase of \$1.60/MWh or about 8% compared to the existing DOS Term charge. This increase is comparable to the proposed increase in the DOS 7 Minutes and DOS 1 Hour charges, and is considered appropriate by the AESO.

A charge of \$21.60/MWh is therefore included in the DOS Term rate schedule in section 6 of this refiling.

14 Amend Rate FTS to Align With Rate DTS

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Direction

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. [p. 75]

Response

Rate FTS has been amended to align with Rate DTS, in Schedule 5.12 in the rate calculations in section 5 of this refiling, and in the FTS Rate Schedule in the tariff in section 6.

The specific amendments to Rate FTS are:

- (a) Bulk system and local system charges have been unbundled consistent with corresponding unbundled charges in Rate DTS.
- (b) The demand component of the bulk system charge is collected on the basis of a 12 CP coincident metered demand consistent with the recovery of the corresponding charge in Rate DTS.
- (c) The unbundled local system charge continues to recover the actual cost of the ATCO Electric line providing service to Fort Nelson, as this cost is greater than the charges that would accrue to BC Hydro using the DTS local system charge, consistent with Direction 7 of Decision 2005-096 on the AESO's 2005-2006 General Tariff Application.

All other components of Rate FTS remain as filed in the AESO's 2007 Application.

15 Identify Export Rates Not Offered Until OASIS Is Complete

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Direction

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. [p. 83]

Response

The AESO has further continued to investigate the implementation of an Open Access Same-time Information System (OASIS) or similar system since the filing of reply argument. OASIS implementation was assessed in consideration of other projects requiring IT time and resources, in particular an upgrade to the System Coordination Centre Energy Management System (EMS) to address system obsolescence and enhance system operation and security. The AESO determined, during the course of the 2008-2009 Budget Review Process, that the EMS upgrade has more urgent and higher priority, resulting in the deferral of implementation of an OASIS or similar system to 2009 or later.

The AESO considers that it is not practical to implement multiple export rates with different priorities without an OASIS or similar system, and that until such a system is implemented only one export opportunity service should be offered. The AESO will therefore immediately offer export service only under Rate XOS 1 Hour as part of its approved tariff, which essentially represents a continuation of the current Export Opportunity Service Rate EOS.

However, the AESO proposes to include Rate XOS 1 Month in its tariff, with a condition in the rate schedule that it will not be available until an OASIS or similar system is implemented. The following availability condition is therefore included in Rate XOS 1 Month in the tariff in section 6 of this refiling:

- Available: Export Opportunity Service (1 Month) is available:
- after an Open Access Same-time Information System (OASIS) or similar system has been implemented by the AESO, and
 - in hours when sufficient transmission capacity exists to accommodate the capacity scheduled for service....

Inclusion of Rate XOS 1 Month in this refiling will allow the rate to be offered after an OASIS or similar system is implemented, without requiring additional specific approval from the AUC or further delay until a subsequent tariff application.

16 Adjust XOS Charges in Accordance With TCE Figure 4

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Direction

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. [p. 87]

Response

The \$3.98/MWh and \$4.36/MWh charges determined in Figure 4 on page 36 of TCE's evidence included amounts with respect to transaction fees and losses. Those amounts are recovered in the AESO's export opportunity rates respectively as a fixed charge per billing period and as a variable energy charge based on loss factor and pool price. The energy transfer charge included in the XOS rates would therefore be less than the \$3.98/MWh and \$4.36/MWh charges due to the exclusion of transactions fees and losses from these amounts.

As well, the AESO's 2007 DTS revenue requirement has been updated in this refiling for interim or final approvals of TFO costs as required by Direction 1. The final DTS revenue requirement, converted into \$/MWh amounts in accordance with the approvals summarized in Direction 7, is provided in Schedule 5.9 in section 5 of this refiling and summarized below.

DTS Rate Components	\$/MWh		
	Fixed	Variable	Total
Interconnection – Bulk System	\$ 3.03	\$ 0.66	\$ 3.69
Interconnection – Local System	1.26	0.28	1.54
Interconnection – POD	3.61	-	3.61
Operating Reserve	-	2.29	2.29
Voltage Control	-	0.93	0.93
Other System Support	0.14	-	0.14
Total	\$8.05	\$4.16	\$12.21

The AESO has therefore updated TCE's Figure 4 to determine the energy transfer charges applicable to Rate XOS 1 Hour and XOS 1 Month, as provided in the following table.

Line No.	Cost Component	Existing EOS	XOS 1 Hour	XOS 1 Month
1	Transaction Fee	\$0.05	\$0.05	\$0.05
2	Incremental Losses	1.91	1.91	1.91
3	Interconnection – Bulk System	1.41	0.66	0.66
4	Interconnection – Local System	0.26	0.28	0.28
5	Operating Reserve (9% × DTS Amount)	-	0.21	0.21
6	Voltage Control	-	-	-
7	Other System Support	-	-	-
8	Additional Contribution	-	0.88	1.24
9	Total	\$3.63	\$3.99	\$4.36
10	Percent Increase over EOS	-	10%	20%
11	Energy Transfer Charge – Sum of Lines 3 to 8	\$1.67	\$2.03	\$2.40

Energy transfer charges of \$2.03/MWh and \$2.40/MWh are therefore included, respectively, in the XOS 1 Hour and XOS 1 Month rate schedules in the tariff in section 6 of this refiling, together with losses charges based on location specific loss factors and transaction fees of \$500.00 per billing period.

There are no associated adjustments required to the terms and conditions of service to reflect the above revisions.



17 Implement Rate IOS as Filed

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Direction

No party expressed any concern with respect to this rate [Import Opportunity Service Rate IOS]. The Board finds the AESO proposal to be reasonable and it is approved as filed. [p. 87]

Response

Rate IOS as filed is included in the tariff in section 6 of this refiling.

17A Implement Approved Maximum Investment Function

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Direction

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:

$$Y = \$1.028 \text{ million} + \$0.578 \text{ million/MW for the first 7.5 MW} + \\ \$0.200 \text{ million/MW for the next 9.5 MW} + \\ \$0.118 \text{ million/MW for the next 23 MW} + \\ \$0.062 \text{ million/MW for all MW above 40.0 MW}$$

[p. 98]

Response

The maximum investment function as provided above has been implemented in Article 9.6(a)(i) of the tariff included in section 6 of this refiling. The maximum investment amounts provided above would be available with a contract term of 20 years; the amounts in the tariff have been divided by 20 to determine the per year maximum investment amounts available with contract terms of less than 20 years.

As discussed in part (g) of the response to Direction 7, the AESO considers that the substation fraction should continue to apply to the customer (\$/year) component of the investment function, but not to any of the demand (\$/MW) components of the function. The substation fraction has accordingly been included in the fixed component of the investment function in Article 9.6(a)(i).

Finally, as discussed in response to Direction 10, the maximum local investment is reduced for services receiving the Primary Service Credit. The reduced investment is described in that response, and is provided in Article 9.6(a)(ii) of the tariff in section 6 of this refiling.

Direction

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. [p. 106]

Response

The AESO will respond to Direction 20A from Decision 2005-096 in its next GTA. As suggested in the AESO's response to Direction 6 on assessing the cost and time to study TFO O&M cost causation, it may be efficient to respond to Direction 18 as part of the study required by Direction 6.

Direction

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 refiling 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.

[p.107]

Response

The AESO has revised the wording of Article 9.4 in the tariff in section 6 of this refiling, in accordance with the above direction.

Direction

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. [p. 111]

Response

The AESO will conduct further analysis and stakeholder consultations on staged contribution payments, and propose an appropriate tariff provision in its next GTA.

Direction

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 refiling application pursuant to this Decision. [p. 116]

Response

The AESO has revised Article 14.6 to include on paragraphs 14.6(a) and 14.6(b) in the tariff in section 6 of this refiling, in accordance with the above direction.

The AESO notes that a reference to Appendix B in Article 14.6(b) has been updated to correctly refer to in the Appendix to the Rate Schedules.

Direction

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. [p. 117]

Response

The AESO has revised Article 16, incorporating the Exhibit 349 changes, in the tariff in section 6 of this refiling, in accordance with the above direction.

23 Provide an Update With Respect to EnCana Countess Facility Page 1 of 2

Direction

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 [of reassessing and applying appropriate charges with respect to the original contribution paid by EnCana in respect of the Countess Facility]. [p. 121]

Response

The AESO provides the following information as an update on the actions taken and final payments made with regards to the EnCana Countess Facility.

As a result of Decision 2006-046, the AESO further reviewed the circumstances around the EnCana Countess project to assess whether the original customer contribution determination was valid or if an adjustment was necessary. Based on the review, in June 2006 the AESO determined that the second transformer originally installed for the facility did not constitute a component of "AESO Standard Facilities".

In May 2006, Niska Gas Storage had purchased the Countess gas storage facility from EnCana. Based on the determination summarized above, the AESO initiated discussions with this customer and offered the following options to Niska.

1. The AESO would remove the second transformer and utilize it at another location on the transmission system at the next practical opportunity. No service interruption would occur to the Countess facility, and the cost of relocating the transformer would not be charged to Niska. No adjustment to the contribution would be necessary.
2. Niska could pay a contribution for the cost of the second transformer, reflecting the fact that if they wish to keep it in service and remain at a contract level at or below the capability of a single 25 MVA transformer, it would be considered a facility in excess of AESO standard facilities.
3. Niska could re-contract to a level above the capability of a single 25 MVA transformer. The AESO would then determine what facilities are reasonably required to provide the requested service level, and would assess the contribution on that basis.

In July 2006 Niska notified the AESO that they did not require the second transformer, and gave the AESO permission to remove it from the Countess site.

The transformer is a 130/4.16 kV transformer. The secondary voltage is a typical industrial voltage and not a typical DFO distribution voltage. The AESO actively investigated placing the transformer at an alternate site, but the voltage of the transformer is not suited for most standard facilities.

The AESO accordingly exercised prudence and did not expend system funds to remove the transformer from service until it was determined that the transformer was suitable for service

at another location. The AESO has not as yet identified a project where the installation of this transformer would be feasible and appropriate. In effect, the transformer is considered a “spare” and remains available for relocation to a suitable alternate service when needed.