Meeting notes and other information distributed as part of the AESO’s consultation on its 2010 tariff are attached as listed below and posted on the AESO website. Please note that Excel workbooks are not included with this response, and may be accessed on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff.

AESO Stakeholder Meetings
- 2009-11-26 AESO Responses to Stakeholder Comments
- 2009-11-03 AESO Presentation
- 2009-11-03 TFO O&M Cost Study Presentation
- 2009-11-03 Draft Terms and Conditions
- 2009-10-13 AESO Connection Model and 2010 GTA Update - Stakeholder Invitation

Delay in Application Filing
- 2009-09-16 Application Delay

POD Cost Function and Investment Level Update Working Group
- 2009-09-16 POD Charge Calculation (Excel, 0.2 MB)
- 2009-09-09 POD Cost Data Information
- 2009-09-09 POD Cost Update Data (Excel, 0.4 MB)
- 2009-06-11 Meeting Agenda and Information
- 2009-06-12 Meeting Notes for May 29, 2009
- 2009-06-12 POD Charge Calculation (Excel, 0.2 MB)
- 2009-06-12 AltaLink Cost Index Information
- 2009-05-28 Meeting Agenda and Information
- 2009-05-28 POD Cost Update Paper
- 2009-05-28 POD Cost Update Data (Excel, 0.3 MB)

TFO O&M Cost Causation Study Working Group
- 2009-09-23 Meeting Agenda
- 2009-09-14 Draft TFO O&M Cost Study
- 2009-06-17 Meeting Agenda
- 2009-06-17 Meeting Notes for May 25, 2009
- 2009-06-17 TFO O&M Cost Causation Study Scope
- 2009-05-25 Meeting Agenda and Information

DTS Operating Reserve Charge Design Working Group
- 2009-06-29 Meeting Agenda
- 2009-06-04 OR Charge Design Paper

Fort Nelson Rate FTS Working Group
- 2009-05-30 Meeting Agenda and Information

Export and Import Rates XTS and ITS Working Group
- 2009-05-31 Meeting Agenda and Information
Deferral Account Riders B and C Working Group
- 2009-12-04 Stakeholder Comments on Process Changes
- 2009-11-26 Updated Reconciliation Process Discussion Paper
- 2009-11-26 Updated Stakeholder Comment Form (Microsoft Word)
- 2009-11-19 Reconciliation Process Changes Presentation
- 2009-11-19 Stakeholder Comment Form (Microsoft Word)
- 2009-11-06 Consultation on Reconciliation Process Changes
- 2009-06-26 AESO Prior Year Amounts (Excel, 0.1 MB)
- 2009-06-26 Meeting Notes for Jun 8, 2009
- 2009-06-08 EPCOR Rider C History (Excel, 0.2 MB)
- 2009-06-05 Meeting Agenda and Information

Tariff Changes Related to Transition of Authoritative Documents (TOAD) Working Group
- 2009-10-22 Incorporation of ISO Rules Into Tariff
- 2009-10-22 Comment Form (Word, 0.1 MB)
- 2009-06-08 Meeting Agenda and Information

Amortized Customer Contribution Option and Other Contribution Provisions Working Group
- 2009-07-06 AESO Credit Policy Presentation
- 2009-07-06 Management Fee Discussion From Decision 2009-087
- 2009-06-25 TransCanada Rider I Proposal Information
- 2009-06-09 Meeting Agenda and Information

Tariff Provisions Related to Customer-Owned Substations Working Group
- 2009-06-10 Meeting Agenda and Information

Tariff Consultation Working Groups Information
- 2009-06-17 Working Groups Final Terms of Reference
- 2009-05-28 Participant Update
- 2009-05-21 Final Participant List
- 2009-04-30 First Round Participant List
- 2009-04-22 Working Groups Invitation and Terms of Reference
- 2009-04-01 Working Group Signup and Comment Form (Word)

AESO Stakeholder Meetings
- 2009-06-24 Presentation
- 2009-06-11 AESO Meeting Invitation
- 2009-04-15 Presentation
- 2009-04-01 AESO Invitation and Process Update

AESO Initial Consultation
- 2009-02-05 AESO Initial Process
Participants in AESO 2010 Tariff Consultation  
Members of AESO 2010 Tariff Consultation Working Groups  
AESO Stakeholders

Dear Stakeholder:

Re: **AESO Responses to Stakeholder Comments on 2010 Tariff Proposals**

During the consultation meeting on the AESO’s 2010 tariff application held on November 3, 2009, stakeholders provided comments on certain proposals included in the AESO’s presentation. The AESO has considered those comments, and provides the following responses.

In addition, the AESO has delayed the filing of the 2010 tariff application to mid-December instead of the end-of-November date announced at the stakeholder session. The extension will allow the suggestions of stakeholders to be addressed in the application, as well as further refinement of the proposed tariff and finalization of the application.

The AESO summarizes its responses to stakeholder comments on the 2010 tariff proposals as follows.

1 **Provisions Relating to Confidential Information and Dispute Resolution**

The AESO proposed that the 2010 tariff incorporate by reference the ISO rule provisions for confidential information and dispute resolution. Written consultation was conducted on this approach for both the ISO rules and the tariff. Stakeholders commented that such incorporation by reference could potentially subject a party to penalties or sanctions under both the ISO rules and the tariff for a single event of non-compliance (sometimes referred to as “double jeopardy”). As well, stakeholders questioned the wording used in the draft terms and conditions to incorporate the ISO rule provisions by reference.

The AESO has further examined this issue and has concluded that no substantive distinctions exist between parties subject to the tariff and those subject to the ISO rules with respect to those provisions. In both cases, the party is a market participant and is subject to all applicable provisions of both the ISO rules and the tariff. As the ISO rule provisions relating to confidential information and dispute resolution are not restrictive, they apply to all information exchanges and all disputes involving the AESO and market participants, including information and disputes related to the AESO tariff. Those ISO rule provisions do not need to be incorporated by reference or otherwise specifically included in the tariff.
To ensure clarity of the applicability of these provisions to parties under the AESO tariff, the AESO will discontinue the use of the term “customer” in the tariff. Instead, the term “market participant” will be used throughout the tariff similar to its current use in the ISO rules. The rates and individual sections of the terms and conditions will describe the applicability of specific tariff provisions to different market participants, where appropriate. Therefore, the AESO tariff will not contain provisions relating to confidential information or dispute resolution, as those matters are addressed comprehensively in the relevant ISO rules.

The AESO considers this approach will bring clarity and consistency to the AESO’s authoritative documents.

2 Treatment of Isolated Generation Fuel Cost in Transmission Operating and Maintenance Cost Study

During Arnie Reimer’s summary of the conclusions of his study of transmission operating and maintenance cost, stakeholders questioned the classification of fuel cost for ATCO Electric’s isolated generation as energy-related. Mr. Reimer has reviewed the classification of that cost, and concluded it should remain energy-related. The cost clearly varies directly with the volume of energy consumed in isolated communities. Classifying that cost as energy-related, and reflecting that classification in the AESO’s tariff, will provide a price signal to reduce energy consumption which will in turn reduce isolated generation costs. Classifying the cost as demand-related or customer-related would provide no relevant price signal and would be expected to have little effect in reducing energy consumption.

The AESO further notes that its revenue requirement includes an isolated generation credit which reflects payments from retailers to the AESO based on pool price for the energy used in communities served by isolated generation, in accordance with the \textit{Isolated Generating Units and Customer Choice Regulation}. The AESO considers that the isolated generation credit should similarly be classified as energy-related, and should offset the isolated generation fuel cost. Depending on the magnitude of the balance of energy-related costs and the charge that would result if those costs were recovered through an energy charge, the AESO will determine whether it is appropriate to propose an energy component for the point of delivery charge in Rate DTS.

3 Treatment of Remedial Action Scheme Costs

In the draft terms and conditions to be included in the 2010 tariff, the AESO proposed that remedial action scheme costs would be considered participant-related (previously termed customer-related) costs rather than system-related costs. Some stakeholders suggested that remedial action scheme costs should sometimes be considered system-related costs. The AESO has reviewed the treatment of such costs, including information presented in the AESO discussion paper on “RAS in the Planning Stage”, published on July 3, 2009. The AESO has concluded it remains appropriate to treat the costs of remedial action schemes associated with a connection project as participant-related costs, for the reasons discussed in that paper and summarized as follows.

The AESO first notes that a remedial action scheme may be implemented as part of a system project. In such a case, the costs would not be associated with a connection project for system access service and therefore would not be considered participant-related costs.
When the AESO receives a request from a market participant for a new system access service, or for an increase to an existing system access service, the AESO makes an assessment identifying the required facilities for and timing of the requested connection. When assessing the request, the AESO may allow a connection to proceed if specific reliability issues in the area are addressed. The AESO may determine that a remedial action scheme can be offered to allow load or generation to connect to the system before the transmission system has been reinforced to provide unconstrained access. If a temporary remedial action scheme is a viable option and is feasible, the AESO may proceed to connect the market participant. The market participant has the choice of delaying their connection until needed facilities are built or accepting a temporary remedial action scheme as a condition of connection.

As a remedial action scheme associated with a connection project is required for the connection of a market participant and is implemented at the choice of the market participant, the AESO considers that the associated costs should be considered participant-related.

**4 Interim Refundable Treatment of Current Contribution Policy**

Stakeholders suggested that in its 2010 tariff application the AESO should request that its currently-approved contribution policy be treated as interim and refundable effective January 1, 2010. The AESO acknowledges that the proposed 2010 contribution policy includes material increases to investment levels as well as other enhancements that may result in customers delaying projects in anticipation of the proposed contribution policy being approved. The AESO considers such delays to generally be inefficient, and will therefore recommend the currently-approved contribution policy be considered interim and refundable during 2010 and that the final contribution policy, when approved, be retroactive to January 1, 2010.

The contribution policy that applies to a connection project will remain the one which is in effect (on a final basis) on the date the Alberta Utilities Commission (“Commission”) issues permit and licence for the connection project, as is the current practice of the AESO and as is explicitly stated in the proposed 2010 terms and conditions.

The AESO considers that other changes being proposed in its 2010 tariff application should not be applied retroactively, as they are either less material (such as changes to many rate levels) or are unsuited to retroactive implementation (such as the hourly allocation of operating reserve costs in Rate DTS). The AESO will therefore request that all aspects of its 2010 tariff, other than the contribution policy, be implemented on a go-forward basis as of the effective date approved by the Commission.

**5 Basis for Wires Costs Included in AESO Revenue Requirement**

Stakeholders suggested the AESO consider revising its approach of including in the wires cost component of its revenue requirement only tariffs that have been approved on an interim or final basis for owners of transmission facilities (“TFOs”). In particular, where a TFO has applied for an increase to its tariff for the test year but that increase has not yet received Commission approval, stakeholders suggested that including costs mid-way between the currently-approved and the applied-for TFO tariffs may result in AESO rates recovering amounts nearer the final approved TFO costs. Such an approach could reduce the balances which the AESO then needs to recover through deferral account mechanisms such as Rider C and later reconciliations.

The AESO has examined recent TFO tariff approvals and has found that the suggestion has merit. Initial results indicate that determining wires costs which include about three-quarters of
any applied-for increases above currently-approved TFO tariffs would likely reduce deferral account balances recovered through Rider C. The AESO expect to include such a proposal in its 2010 tariff application.

6 Conclusion

The AESO is in the final stages of incorporating these changes in its 2010 tariff application, as well as finalizing the other proposals and improvements discussed during stakeholder consultation. The AESO will file the application as soon as possible, and appreciates stakeholders’ interest and participation in the consultation processes related to the application. All information related to the 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ➔ Current Consultations ➔ 2010 Tariff.

If you have any comments or questions on the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
    Lee Ann Kerr, Manager, Tariff Applications, AESO
    Raj Sharma, Senior Tariff Analyst, AESO
AESO 2010 Tariff Stakeholder Consultation

John Martin, Lee Ann Kerr, and Raj Sharma
AESO Regulatory
Arnie Reimer, PS Technologies
November 3, 2009 — Calgary

Agenda

• Introduction (slides 1-4)
• Studies
  – POD cost function update (slides 5-19)
  – TFO O&M cost causation study (separate presentation)
• 2010 rate proposals (slides 20-39)
  Break
• 2010 terms and conditions proposals (slides 40-80)
• Next steps (slides 81-84)
AESO 2010 Tariff Application

- To be filed on November 30, 2009
  - Delayed from initial target of late September 2009
- Proposals being presented are still preliminary and subject to change in application when filed
- Working group meetings held in spring and summer 2009
  - Working group information posted on AESO website
- 2010 tariff will build on existing tariff
  - Changes to rates include hourly DTS operating reserve charge and additional export and import rates
  - Changes to terms and conditions include revisions to customer connection process, contribution policy, and revisions to align and consolidate information

Meeting Objectives

- Understanding of results of studies being finalized for tariff application
- Understanding of proposals for tariff changes
  - Proposals are discussed “without prejudice” and may still be subject to change in tariff application when filed
- Please ask questions during presentation
POD Cost Function and Investment Level Update

Raj Sharma
Senior Tariff Analyst, AESO Regulatory

POD Cost Function and Investment Level Update Working Group

• Working group participants:
  AltaLink, Dual Use Customers, ENMAX, TransCanada, and UCA
• Data and recommendations posted on AESO website
  – POD cost update data, POD cost update paper, AltaLink cost index information, POD charge calculation, and draft recommendations
Updated “Greenfield” Data Set

- 48 load-only connection projects included in POD cost function in 2007 tariff proceeding
  - From 1987 to 2006
  - Escalated to 2007 using Alberta CPI in 2007 GTA study
- Removed one project that was cancelled
- Added 17 new load-only connection projects
  - From 2006 to 2009
- Updated project costs to most recent estimates or final costs
  - Minimum +20%/-10% (“PPS”) estimate or better

Composite Price Index

- Project costs escalated to 2008 using composite price index
- Based on four historical price indices from Statistics Canada
  - Canada equipment index ► substations
  - Canada materials index ► transmission line
  - Alberta industrial services index ► engineering
  - Average of Calgary and Edmonton industrial structures indices ► construction
- Historical price indices weighted in proportion to average weighting of cost components for connection projects
Composite Price Index (cont’d)

- For 1987-2008, average year over year change for composite price index is 3.54%
  - Compared to 2.99% for the Alberta CPI
- Project costs escalated from 2008 to 2010 using forecast of Alberta CPI
- For 1987 to 2010, average year over year change for the cost index used is 3.37%
POD Cost Function Increase

- 2007 POD cost function based on Standard Facility cost:
  \[ \text{Cost} = 2,213,108.54 \times \text{MW}^{0.37} \]
- 2010 POD cost function based on total cost:
  \[ \text{Cost} = 2,761,700 \times \text{MW}^{0.4089} \]
- Power curve remains “best fit” to data
- Shape of curve essentially unchanged
- Increases of:
  - 27% at 7.5 MW
  - 32% at 17 MW
  - 38% at 40 MW

Impact on 2009 Demand Transmission Service POD Charge

<table>
<thead>
<tr>
<th>Tier</th>
<th>2009 DTS POD Charge Using Current POD Cost Function</th>
<th>2009 DTS POD Charge Using New POD Cost Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>First (7.5×SF) MW of billing capacity</td>
<td>$3,955 / MW</td>
<td>$3,926 / MW</td>
</tr>
<tr>
<td>Next (9.5×SF) MW of billing capacity</td>
<td>$1,368 / MW</td>
<td>$1,465 / MW</td>
</tr>
<tr>
<td>Next (23×SF) MW of billing capacity</td>
<td>$802 / MW</td>
<td>$891 / MW</td>
</tr>
<tr>
<td>All remaining MW of billing capacity</td>
<td>$425 / MW</td>
<td>$490 / MW</td>
</tr>
<tr>
<td>Substation fraction (customer charge)</td>
<td>$7,030 / month</td>
<td>$5,607 / month</td>
</tr>
</tbody>
</table>
2010 Cost Function Is About 35% Higher than 2007 Cost Function

Shape of Curve Is Essentially Unchanged
Total Cost versus Standard Facility Cost

- Standard Facilities approach applied to the Standard Facilities cost of the 64 projects in data set with a multiplier of 1.15 results in total investment of about $471 million.
- A multiplier of 1.06 applied to the raw cost function based on total project cost results in about the same total investment for all 64 projects of about $472 million.
- Out of 64 projects, investment was equal for 30 projects, from 0% to 3% lower for 27 projects and from 2% to 8% higher for 4 projects.
- For 3 projects investment was higher by 19%, 29%, and 46%.
- For 58 projects difference in investment was within ±3%.

Change in Investment

- Bar chart showing investment in millions for both standard facility cost and total cost, with bars indicating the change in investment using a multiplier of 1.15 compared to a multiplier of 1.06.
Advantages of Using Total Cost

- Investment is effectively limited through the maximum investment function based on total cost.
- There is no longer a need to expend significant AESO, TFO, and customer resources on determining, evaluating, and estimating costs for Standard Facilities which may never be constructed.
- Connection for a customer will be based on those facilities which the customer considers necessary for the connection.

Primary Service Credit

- Primary Service Credit (PSC) determination is based on the division of cost of connection between substation related costs and line related costs.
- Greenfield projects for which such division is available were used for the calculation.
- Ratio of total substation related cost (that is, excluding line related cost) to total project cost was calculated to be 0.55 in the last study. Based on the updated data and additional projects included in the data set for the AESO 2010 General Tariff Application, this ratio now increases to 0.78.
Next Steps

- Will be incorporated into AESO 2010 General Tariff Application
- Direct comments, feedback, and suggestions to John Martin or Raj Sharma

2010 Rate Proposals

John Martin
Director, Tariff Applications, AESO Regulatory
Revenue Requirement

- Rate levels will be based on 2010 costs as presented to stakeholders in AESO Budget Review Process
  - Wires costs will be updated with recent TFO tariff approvals

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>2010 Forecast $ 000 000</th>
<th>2009 Forecast $ 000 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wires</td>
<td>$537.5</td>
<td>$523.7</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>144.3</td>
<td>282.2</td>
</tr>
<tr>
<td>Losses</td>
<td>173.6</td>
<td>238.0</td>
</tr>
<tr>
<td>Administrative</td>
<td>79.4</td>
<td>80.0</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$934.8</td>
<td>$1 123.9</td>
</tr>
</tbody>
</table>

Demand Transmission Service
Rate DTS

- Connection charge updated to reflect
  (a) updated POD cost function,
  (b) updated wires cost functionalization and classification from TFO O&M cost causation study, and
  (c) 2010 forecast costs and billing determinants
  - No changes to structure, billing determinants, or methodology
DTS Connection Charge

Preliminary Comparison

<table>
<thead>
<tr>
<th>Component</th>
<th>2010 Preliminary</th>
<th>2009 Rates Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$1 959.00/MW</td>
<td>$2 229.00/MW</td>
<td></td>
</tr>
<tr>
<td>$0.68/MWh</td>
<td>$0.78/MWh</td>
<td></td>
</tr>
<tr>
<td>Local System</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$860.00/MW</td>
<td>$653.00/MW</td>
<td></td>
</tr>
<tr>
<td>$0.42/MWh</td>
<td>$0.32/MWh</td>
<td></td>
</tr>
<tr>
<td>Point of Delivery</td>
<td></td>
<td></td>
</tr>
<tr>
<td>First (7.5 × SF) MW</td>
<td>$4 207.00/MW</td>
<td>$3 955.00/MW</td>
</tr>
<tr>
<td>Next (9.5 × SF) MW</td>
<td>$1 569.00/MW</td>
<td>$1 368.00/MW</td>
</tr>
<tr>
<td>Next (23 × SF) MW</td>
<td>$955.00/MW</td>
<td>$802.00/MW</td>
</tr>
<tr>
<td>All Remaining MW</td>
<td>$525.00/MW</td>
<td>$425.00/MW</td>
</tr>
<tr>
<td>Fixed Component</td>
<td>$6 008.00 × SF</td>
<td>$7 030.00 × SF</td>
</tr>
</tbody>
</table>

SF = Substation Fraction

Hourly Operating Reserve Charge

- Operating reserve charge revised to:

  metered energy in each hour ×
  operating reserve unit cost in each hour

  where operating reserve unit cost is the total cost of
  operating reserves in the hour divided by the sum over all
  Rate DTS customers of the metered energy for each
  customer in the hour

- AESO will maintain single-block operating reserve charge to
  allow estimation of magnitude of charge

- Operating reserve charge deferral account expected to be
  significantly reduced
Other Rate DTS Components

### Preliminary Comparison

<table>
<thead>
<tr>
<th>Component</th>
<th>2010 Preliminary</th>
<th>2009 Rates Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Reserve</td>
<td>3.17% × Pool Price</td>
<td>4.82% × Pool Price</td>
</tr>
<tr>
<td>Voltage Control</td>
<td>$0.39/MWh</td>
<td>$0.65/MWh</td>
</tr>
<tr>
<td>Other System Support</td>
<td>$59.00/MW</td>
<td>$62.00/MW</td>
</tr>
<tr>
<td>Power Factor Deficiency</td>
<td>Being Finalized</td>
<td>$400.00/MVA</td>
</tr>
</tbody>
</table>

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Fort Nelson Demand Transmission Service Rate FTS

- Incremental costs will be assessed to Alberta and Fort Nelson loads based on incremental load growth in each region
  - Based on load growth above load forecast on which northwest transmission development was based
- Incremental costs will be recovered from Fort Nelson through Local System component of Rate FTS
  - Similar to current recovery of wires costs through local system charge
- Incremental TMR costs will be assessed to Alberta and Fort Nelson based on load in each region during hours in which TMR is required
Demand Opportunity Services
Rates DOS

- No changes to structure, billing determinants, or methodology
  - Rate levels will change to reflect changes in costs
- Rights and obligations which currently exist in tariff, OPPs, and business practices will be consolidated into rate sheet and terms and conditions section
  - Other information will be consolidated into an information document

Export Transmission Service
Rates XTS

- AESO is finalizing proposal for hourly, daily, weekly, monthly, and annual “firm” export services comparable to Rate DTS load service
- Costs would generally be comparable to costs on Rate DTS
  - All rate versions would be based on the same unit costs
  - Distinctions in priority are through duration of contracted transfer
- Rates could not be implemented until an OASIS or similar system is available
Export Opportunity Services Rates XOS

- AESO is finalizing proposal for hourly, daily, weekly, monthly, and annual opportunity export services comparable to existing Rates XOS
- Costs would generally be comparable to costs on existing Rates XOS
  - All rate versions would be based on the same unit costs
  - Distinctions in priority are through duration of contracted transfer
- No changes to structure, billing determinants, or methodology
  - No changes expected yet from implementation of WECC BAL-002 contingency reserve standard

Demand Under-Frequency Load Shedding Credit Rate UFLS

- No changes to structure or billing determinants, or to applicability of rate
- Provisions from terms and conditions will be incorporated into rate sheet, where applicable
Primary Service Credit
Rate PSC

• No changes to structure, billing determinants, or methodology
  – Rate levels will change to reflect changes in costs
• 78% of DTS POD charge components represent share of costs attributable to substation
  – Based on updated data set used for POD cost function update
• Primary service credit will apply at all sites where substation is not owned by TFO
  – No longer a customer option
• Primary service credit will apply in conjunction with reduced maximum investment levels

Supply Transmission Service
Rate STS

• No changes to structure, billing determinants, or methodology
• RGUCC levels will reduce in accordance with existing schedule of charges
• Some provisions from terms and conditions will be incorporated into rate sheet
  – For example, provision that generators contracted under Small Power Research and Development Act are not subject to Rate STS
Import Transmission Service
Rate ITS

- AESO still debated conceptual framework for “firm” import transmission service
  - Key criteria for Rate STS is merit order dispatch, which is not applicable to import offers
- Work may not be completed in time to be included in 2010 tariff application, and may require a supplemental or amendment application

Import Opportunity Services
Rates IOS

- No changes to structure, billing determinants, or methodology
  - Single import opportunity service seems to be sufficient
Riders

- DAT Riders A1–A4: no changes
- Deferral Account Adjustment Rider C:
  - change to include prior year balances
  - more explicit description of calculation
  - possible changes to reconciliation approach and process
- Losses Calibration Factor Rider E: no change
- Balancing Pool Consumer Allocation Rider F: no change

Deleted Riders

- Working Capital Deficiency/Surplus Rider B
  - Has not been used since Rider C was implemented
  - Appears to no longer be of value to AESO
- Bill Impact Mitigation Rider G
  - Expires December 31, 2009
- Interim Refundable Fort Nelson Rider H
  - Addressed as part of Rate FTS
**Amortized Contribution Option**

**Rider I**

- Would allow customers to pay customer contributions over time rather than as up-front cash payment as currently required
- Would be available to both DTS and STS customers
- Would be implemented in conjunction with revised financial obligation provisions of terms and conditions
  - Customer would be required to pay contribution while connection project is under construction
  - After commercial operation, contribution could be converted into amortized payment
- Payment would be amortized over investment term with a small risk premium included in payment calculation

**Wind Forecasting Cost Recovery**

**Rider J**

- AESO is implementing a centralized wind forecasting service with costs recovered from wind generators
- Rider proposed to escalate over four years as a simple $/MWh charge:
  - 2010: $0.23/MWh
  - 2011: $0.25/MWh
  - 2012: $0.28/MWh
  - 2013 and later years: $0.31/MWh
- Rider would include annual adjustment to reflect variance of actual costs minus forecast costs, less variance of actual revenues minus forecast revenues
Appendix
Regulated Generating Units

- No material changes contemplated
- All appendices being considered appendices to tariff
  - No more distinction between rates appendices and terms and conditions appendices

2010 Terms and Conditions Proposals

Lee Ann Kerr
Manager, Tariff Applications, AESO Regulatory
Terms and Conditions Changes

- Updated throughout to reflect changes in legislation, rules, and standards
- Updated to align with and incorporate TOAD conventions
- Addresses recommendations of AltaLink consultation on AESO contribution policy
- Includes changes to accommodate new customer connection model
- Significant redrafting and reorganization of:
  - system access service request process
  - financial obligations for connection projects
  - customer contribution policy

AltaLink Consultation Contribution Policy Recommendations

1. Adopt a set of guiding principles into the contribution policy

   The AESO has generally been guided by principles similar to those discussed in the AltaLink recommendation, and will discuss the principles in its application

2. Enhance the definition of standard facilities, and lead a stakeholder consultation to develop Planning Principles and Standards of Service

   To improve process efficiency the AESO is proposing to remove the concept of standard facilities in conjunction with a modified approach to determining maximum investment level
AltaLink Consultation Contribution Policy Recommendations (cont’d)

3. Incorporate a method of fairly allocating the costs associated with an early system rebuild

   In conjunction with an economic evaluation policy, the tariff will provide for an RCN credit for any transformers which are replaced and either suitable for reuse or treated as capital maintenance.

4. Use an inflation factor that is representative of the Alberta market place, and incorporate a mechanism to adjust the contribution formula to account for regulatory lag

   The AESO has developed a composite price index based on Statistics Canada historical transmission price indices and forecast Alberta CPI.

AltaLink Consultation Contribution Policy Recommendations (cont’d)

5. Align the timing of prepaid O&M with costs, and apply prepaid O&M exclusively to facilities in excess of standard

   With the removal of the use of standard facilities, the AESO proposes that O&M will apply to costs of facilities in excess of maximum investment.

6. Provide flexibility on the timing of contribution payments, and provide choices for customers transitioning between tariffs

   The AESO proposes that the contribution policy which applies is the one in effect when P&L is issued for a project, and that security and contribution requirements would be staged to the incurrence of costs by the TFO.
AltaLink Consultation Contribution Policy Recommendations (cont’d)

7. Provide the choice for the contribution payment to be a facilities charge rather than a balance sheet transaction

   The AESO is finalizing a proposal for an amortized contribution option that would include a slight risk premium on the rate of return on which the amortized payment is based

8. Provide new customers with both generation and load at the site, the opportunity to be “load first” in determination of the contribution payment

   The AESO proposed to continue the use of substation fractions to allocate costs and investment between generation and load at a substation

Terms and Conditions Changes

• Proposed terms and conditions are meant to align with new customer connection model

• Revised throughout to replace “interconnection” with “connection”
  – Use the term “connection” when connecting within Alberta
  – “Interconnection” term used when connecting to a neighbouring jurisdiction
Section 4: System Access Service Requests

- Identifies the obligations of the AESO, TFO, and customer as they relate to requests for system access service
- Two types of requests
  - Requests which require the construction of new transmission facilities
  - Requests which do not require construction
- The customer may work with the TFO or other party in the development of a connection proposal
- The AESO will direct the TFO to prepare and submit the NID and facility applications

Section 5: Financial Obligations for Connection Projects

- Proposal consists of a staged approach to payment of security and customer contribution
- The financial obligation amount is initially equal to the costs (estimated) to be incurred by the TFO in preparation of the connection proposal
- Upon acceptance of the proposal, the financial obligation increases by the amount of all subsequent costs (estimated) to be incurred by the TFO to prepare applications
- After AUC approval, the financial obligation increases by monthly amounts equal to the subsequent incurred costs to construct the project
- DFOs do not provide financial security for projects
Section 5: Financial Obligations for Connection Projects (cont’d)

Section 8: Customer Contributions for Connection Projects

- Changes to reflect several accountabilities being transferred to TFOs (for requests that require construction)
- Transaction for customer contribution takes place between customer and TFO
- Facility requirements are determined as those that meet the demand and supply forecast of the customer and reliability and operating requirements
Section 8: Customer Contributions for Connection Projects (cont’d)

- Significantly more detail to aid in the classification of customer-related and system-related costs
  - Aligned customer-related costs for both POD and POS customers
  - Detailed list of those costs that are considered customer-related
    - RAS
    - Shared Facilities
  - More detail around classifying system-related costs
    - Revised definition of “looped”
    - Cap banks, shunt reactors
    - Any facilities identified in the transmission plan or a NID
- TFOs will be making this determination under the new model
Section 8: Customer Contributions for Connection Projects (cont’d)

- Elimination of concept of “standard facilities”
  - The “standard facilities” were implemented when the AESO’s tariff did not align particularly well with the cost of facilities, however, under current tariff there is better alignment between costs and investment levels (as well as POD charge)
  - Inconsistent with historical practice to consider one transformer and one line to be the standard, based on existing connections, half of PODs have more than one transformer, and two-thirds are connected through two or more lines
  - Significant resources are expended by the AESO, TFO, and customer on determining, evaluating, and estimating costs for standard facilities which will never be constructed or pursued

Section 8: Customer Contributions for Connection Projects (cont’d)

- Under 2010 proposed terms and conditions:
  - The customer may choose among alternatives, whatever the customer considers necessary for to meet their own reliability, protection, and operating criteria and standards
  - All connection projects that require the construction of new TFO-owned facilities and are contracting for new MWs will be eligible for investment
  - The chosen alternative is eligible for investment based on contracted MWs
Section 8: Customer Contributions for Connection Projects (cont’d)

- Facilities in excess of “good utility practice”
  - ...means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region and consistently adhered to by the transmission facility owner.

- 12% operations and maintenance added to the amount of demand-related costs which exceed the local investment (as well as facilities in excess of good utility practice)

Section 8: Customer Contributions for Connection Projects (cont’d)

- Equipment used for a connection project will generally be valued at replacement cost new.

- A transformer removed from service at a substation will provide an RCN credit when it is either
  - deemed re-deployable for use at another substation,
  - deemed suitable for use as an operating spare, or
  - treated as a capital maintenance cost

- In all other cases, including when the transformer is scrapped without being treated as a capital maintenance cost, there will be no RCN credit

- This reflects current AESO business practice
Section 8: Customer Contributions for Connection Projects (cont’d)

• “Substation fraction” is calculated, for each contract capacity at a substation, as the individual contract capacity divided by the sum of all contract capacities (under both Rate DTS and Rate STS) for all customers with points of connection at the same substation.

• To allocate costs among multiple customers at one substation, the customer-related costs are multiplied by the substation fraction for each customer.

Section 8: Customer Contributions for Connection Projects (cont’d)

• New investment table, specifies calculation for new connections, as well as capacity increases for existing connections.
  – New proposed investment level represents cost function of total facility costs multiplied by 1.06.
  – Includes investment tiers for service under PSC.
  – Removal of present value calculation for connection projects identifying staged loads at outset of project.
Section 8: Customer Contributions for Connection Projects (cont’d)

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<thead>
<tr>
<th>Tier</th>
<th>Column A</th>
<th>Column B</th>
<th>Column C</th>
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<td>Substation fraction (for new points of delivery only)</td>
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Section 9: Changes to System Access Service After Energization

- Intended to address requests for service which do not require the construction of new facilities
- Incorporates provisions from previous articles
  - Article 9 customer and system contribution policy
  - Article 13 contract capacity increases & allocation
  - Article 14 reductions or termination of contract capacity
Section 9: Changes to System Access Service After Energization (cont’d)

- List of events that will lead to an adjustment (recalculation) of a customer contribution
  - Reclassification of facilities as system or customer
  - Variances between cost estimates and actuals
  - Increase or decrease of contract capacity
- Customer, AESO, or TFO may initiate an adjustment
- Calculates payment due to TFO from customer, or vice versa
- Determination of contributions based on contract changes since any prior contribution calculation

Clarification of the allocation of costs of shared facilities

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<td>245</td>
<td>56.2%</td>
<td>43.8%</td>
<td>43.8%</td>
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</table>

Customer A Share: $1,276,467
Customer B Share: $1,073,333
Section 9: Changes to System Access Service After Energization
(cont’d)

• Clarification of the treatment of reductions or terminations of contract capacity
  – Effective 5 years after date of request
  – Payment in lieu of 5 years' notice
  – More clarity around calculation of PILON
  – PILON payment is in addition to a customer contribution adjustment, where applicable

Section 10: Generating Unit Owner’s Contribution

• Removed reference to “system” in term, to avoid confusion (customer is not responsible for system costs), now aligned with terminology used in legislation
  – 2007 T-Reg uses “generating unit owner’s contribution”
• Separated into its own section
• Payment made to AESO by customer, and refunded to customer by AESO

• Revised ISO Rule 9.5 to incorporate contracted AS energy amounts for capacity factor calculation
Section 1: Applicability and Interpretation

• Interpretation provisions consistent with other AESO authoritative documents
• Incorporation of defined terms contained in Authoritative Documents Glossary
  – Terms used in tariff will be submitted for approval as appendix to application
• Incorporates content from Article 2 of current tariff

Section 2: Provision of and Limitations to Service

• Covers both conditions under which service is provided and possible limitations to that service
• Incorporates content from Articles 3 and 17 of current tariff
Section 3: Customer Connection Requirements

- Removal of information already addressed in technical requirements
- Incorporates remaining content from Article 4 of current tariff

Section 6: Metering

- Removal of information already addressed in AESO Measurement System Standard
- Incorporates remaining content from Article 7 of current tariff
- Appendix A of current terms and conditions removed in its entirety
  - Appendix A contains metering equipment information already covered in AESO Measurement System Standard
Section 7: Provision of Information

- Removal of information already addressed in technical requirements
- Incorporates remaining content from Article 8 of current tariff

Section 11: Ancillary Services (TMR)

- No changes other than formatting to TOAD conventions
Section 12: Demand Opportunity Service (DOS)

- Will incorporate all rights and obligation which currently existing in Operating Policies and Procedures or in Business Practice document
  - Still being worked on
- Other content in those documents will move to an information document

Under-Frequency Load Shedding (Previously Article 12)

- Content consolidated onto rate sheet
Section 13: Financial Security, Billing, and Payment Terms

• Proposed to no longer require security from regulated DFOs
  – Consistent with not requiring security from regulated DFOs for connection projects
• Incorporates remaining content from Article 15 of current tariff

Section 14: Peak Demand Waiver

• Incorporates content from Article 16 of current tariff
  – Some content from Operating Policies and Procedures
Section 15: Limitation of Liability

- Incorporates content from Article 18 of current tariff

Section 16: Confidential Information

- Incorporates, by reference, proposed ISO Rule on confidential information
- Currently in consultation process
Section 17: Dispute Resolution

• Incorporates, by reference, proposed ISO Rule on dispute resolution
• Currently in consultation process

Section 18: Miscellaneous

• Incorporates remaining content from Article 21 in current tariff
Appendix A: Agreement Proformas

- Being reviewed to better address needs of AESO and customers
- Will align with redesigned interconnection process
- Currently Appendix B to terms and conditions

Appendix B: Procedure for TMR Procurement

- No material changes contemplated
Next Steps

John Martin
Director, Tariff Applications, AESO Regulatory

Next Steps

• Some consultation wrap-up on outstanding matters
• Finalization of remaining tariff detail during November
• Tariff application filed on November 30
• Effective date of 2010 tariff likely to be early 2011
Discussion and Questions

For More Information

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  Director, Tariff Applications
  403-539-2465 or john.martin@aeso.ca

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  Manager, Tariff Applications
  403-539-2741 or leeann.kerr@aeso.ca

- Raj Sharma
  Senior Tariff Analyst
  403-539-2632 or raj.sharma@aeso.ca

- Consultation documents on AESO web site at www.aeso.ca
  Tariff ► Current Consultations ► 2010 Tariff
Transmission Operating and Maintenance Cost Study

November 3, 2009
AESO Stakeholder Meeting
Arnie Reimer P. Eng.
PS Technologies

Agenda

• Background
• Capital and Non Capital Related Costs
• Splitting Non Capital Related Costs
  – Operating and Maintenance Costs
  – General and Administration Costs
• Incremental Operating and Maintenance Costs
• Use of Study
• Questions
Background

• Cost Causation Study with 2007 GTA based on capital costs
• Operating and Maintenance costs assumed to track capital costs
• Decision 2007-106
  – 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

Background

• Results from Previous Cost Study

<table>
<thead>
<tr>
<th>Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
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<td>Demand Related</td>
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<td>Totals</td>
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<td>17.4%</td>
<td>40.9%</td>
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</table>

Classification of Costs by Function

| Demand Related | 81.5% | 82.5% | 43.1% |
| Energy Related  | 18.5% | 17.5% | 0.7%  |
| Customer (POD)  | 0.0%  | 0.0%  | 56.2% |
Capital and Non Capital Costs

- Revenue Requirement from four largest TFO’s studied
- Costs first sorted as Capital or Non Capital Costs
  - Capital Costs include depreciation, debt servicing, return, and income taxes
  - Non capital costs defined as those costs not closely tied to capital investment and those where management has some discretion

Capital and Non Capital Costs

- A review of costs show that some costs considered non capital exhibit the characteristics of capital related costs
  - Linear taxes (Taxes other than Income)
  - Structure Payments
  - Capital Related Revenue Offsets
TFO Revenue Requirement

Capital and Non Capital Costs (Approx 70% is Capital, 30% Non Capital)

Revenue Requirement

Non Capital Costs

- Non Capital Costs sorted as:
  - Operating and Maintenance (O&M)
    - O&M costs linked to operation and maintenance of the electric transmission system
  - General and Administration (G&A)
    - G&A costs linked to running the business
Non Capital Costs

Non Capital Costs (Approx 67% is O&M, 33% G&A)

Year

Revenue Requirement

0 20,000,000 40,000,000 60,000,000 80,000,000 100,000,000 120,000,000 140,000,000 160,000,000 180,000,000

2006 2007 2008 2009

G&A

O&M

Functionalization of O&M

• Three Transmission Functions from previous study
  – Bulk
  – Local
  – Point of Delivery
• Distinction on the basis of Voltage Level
Functionalization Example

- Example of Brushing for ATCO

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- Example of Control Centre AltaLink

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<tr>
<td>Lines and Transformers</td>
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<td>Control Center Allocator</td>
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### Functionalization – Summary

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### Classification

- **Operations and Maintenance can not be reliably classified**
  - Operations and Maintenance work is completed on facilities to ensure that they operate reliably and efficiently to meet their original design specifications
- **Operations and Maintenance is classified on the same basis as capital**
- **One exception being fuel cost within transmission which is classified as energy.**
### Classification of Capital Costs

<table>
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<tr>
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### Classified O&M Costs (Non Fuel and Variable O&M) - 2008

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### Classified Costs (O&M Inc Fuel, Var O&M) 2008

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### Classification of O&M Costs

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### Results – Weighting of Capital and O&M

#### Capital Related Costs

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<th>Bulk System</th>
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<th>Totals</th>
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#### Non Capital Costs

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### Classification of Non Capital Costs

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<td>Totals</td>
<td>35.4%</td>
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<td>42.5%</td>
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</table>
Summary

- Non Capital Costs account for 30% of the Revenue Requirement
- O&M costs account for 2/3 of the Non Capital Costs
- Functionalized Non Capital Costs have increased weight on POD and Local functions with reduced weight on Bulk.

Prepaid O&M

- To minimize any subsidies between new customers and existing customers
- New customers that interconnect must pay for Optional Facilities in the form of CIAC
- New customers must also pay for the incremental O&M associated with Optional Facilities on a prepaid basis
- Existing rate is 12% of RCN
Incremental O&M

• Three options for Prepaid O&M charge at time of construction
  – Based on all Non Capital costs
  – Based on all O&M Costs
  – Based on incremental maintenance cost (wrench time)
• Calculated by Cost/RCN

Prepaid O&M

• Based on Non Capital Costs/RCN
  – Approximately 21%
• Based on O&M Costs/RCN
  – Approximately 14%
• Based on Incremental Maintenance/RCN
  – Approximately 2%
• PV over 20 years
Questions and Comments?

- Still a work in progress, updating some actual costs
- Open to suggestions to improve methodology
- Have Study complete by end of November for filing with AESO Application.
- 403.560.0376
CONTENTS

Section 1  Applicability and Interpretation of ISO Tariff
Section 2  Provision of and Limitations to System Access Service
Section 3  Customer Connection Requirements
Section 4  System Access Service Requests
Section 5  Financial Obligations for Connection Projects
Section 6  Metering
Section 7  Provision of Information by Customers
Section 8  Customer Contributions for Connection Projects
Section 9  Changes to System Access Service After Energization
Section 10  Generating Unit Owner’s Contribution
Section 11  Ancillary Services
Section 12  Demand Opportunity Service
Section 13  Financial Security, Billing, and Payment Terms
Section 14  Peak Metered Demand Waiver
Section 15  Limitation of Liability
Section 16  Confidential Information
Section 17  Dispute Resolution
Section 18  Miscellaneous
SECTION 1
APPLICABILITY AND INTERPRETATION OF ISO TARIFF

Applicability

1(1) By applying for or accepting system access service from the ISO, a customer agrees to be bound by the ISO tariff and the ISO rules.

(2) The ISO tariff, including rates, riders, terms and conditions, and appendices, is binding on and defines the rights and obligations of the ISO and its customers with respect to system access services provided by the ISO.

(3) The ISO tariff becomes effective as of the date provided in the revision history of each section and only when approved by the Commission. Each section of the ISO tariff remains in effect until replaced or amended pursuant to the Act.

Conflict

2(1) Nothing in the ISO tariff in any way restricts or limits the powers, duties, and responsibilities of the ISO as described in the Act.

(2) In the event of any conflicts between the terms and conditions and the rates, riders, or appendices of the ISO tariff, the terms and conditions govern.

(3) In the event of any conflicts between the ISO tariff and a clause of a system access service agreement, the ISO tariff governs the specific clause in conflict without affecting or impairing the remaining clauses of the system access service agreement.

Interpretation

3 In the ISO tariff:

(a) tables of contents, section headers, and the use of underlining, bolding, and italicizing are not a part of the tariff but are inserted for convenience of reference only;

(b) words in the singular include the plural and words in the plural include the singular;

(c) words importing male persons include female persons, words importing female persons include male persons, and words importing either sex include corporations;

(d) the provisions of the ISO tariff will be construed as always speaking and will be applied to circumstances as they arise;

(e) “may” is to be construed as permissive and empowering, and “must” or “shall” is to be construed as imperative;

(f) all reference to a time of day in the ISO tariff will mean mountain standard or mountain daylight time in the Province of Alberta, whichever is in effect on the day in question;

(g) words and phrases in bold type have the meanings given to them in the definitions found in the Authoritative Documents Glossary;

(h) titles in italic type indicate documents available on the ISO website and legislation; and
(i) any schedule, table, or appendix attached to the ISO tariff forms a part of the ISO tariff and will be interpreted accordingly.

Jurisdiction

4 Each customer under the ISO tariff, and with respect to any agreement entered into with the ISO, is subject to and attorns to the jurisdiction of the Courts of the Province of Alberta in respect of all matters relating to the Act, its regulations, the ISO tariff, the agreement provisions, and the ISO, notwithstanding the jurisdiction of incorporation or residence of the customer.

Revision History

2009-10-22 Revised to consolidate and update provisions.
Draft released at stakeholder consultation session.
SECTION 2
PROVISION OF AND LIMITATIONS TO SYSTEM ACCESS SERVICE

Provision of Service
1(1) Subject to subsections 2, 3, and 4 below, the ISO agrees to provide system access service, up to and including the point of connection, to all customers who have executed a system access service agreement and abide by this ISO tariff.

(2) The ISO will provide service up to the customer’s contract capacity as set out in the customer’s system access service agreement.

(3) The provision of service is contingent upon any applicable ISO rules or abnormal operating conditions which as defined in the Transmission Regulation include conditions where transmission facilities are out of service, emergency conditions exist, construction or commissioning of transmission facilities occurs, or transmission facility maintenance cannot be coordinated with generating unit outages.

Metered Demand Limitations
2(1) Subject to subsections 2(2) and 2(3) below, the metered demand for a customer taking service under Rate DTS or Rate STS shall not exceed the lesser of the rated capacity or the physical capacity of any transmission facilities comprising its connection. In the event of non-compliance, the ISO shall have the right to discontinue the applicable system access service until the customer installs equipment to limit its metered demand.

(2) A Rate DTS customer may temporarily exceed the rated capacity of transmission facilities comprising its connection only where the customer has a system access service agreement for an opportunity service at the applicable point of delivery.

(3) A Rate STS customer may temporarily exceed the rated capacity of transmission facilities comprising its connection only with the ISO’s consent, obtained on a minimum twenty-four (24) hours’ notice, which will be withheld if the ISO determines that the transmission system cannot safely accommodate the proposed energy without risk of disturbance to other customers.

Withholding Service
3 The ISO, at its sole discretion, may withhold, limit, or discontinue system access service if the customer fails to abide by this ISO tariff. If requested by the customer, the ISO will provide a written explanation for withholding, limiting, or discontinuing system access service.

Service Not Guaranteed
4(1) Although precautions are taken to guard against system access service interruptions, the ISO does not guarantee uninterrupted system access service. Interruptions may be caused by, but not limited to, the following:

(a) scheduled or planned facility maintenance activities;
Section 2
Provision of and Limitations to System Access Service

(b) construction, commissioning, and facility testing activities;
(c) unscheduled or unplanned events (such as, but not limited to, emergency equipment maintenance and emergencies);
(d) force majeure;
(e) breaches of obligations owed to the ISO by its suppliers or customers; or
(f) as otherwise expressly allowed by a rate or rider in the ISO tariff.

(2) Whenever system access service has been interrupted, limited, or reduced for reasons other than a breach of this ISO tariff by the customer, the ISO will make all reasonable efforts to ensure that service is restored as soon as practicable after the interruption, limitation, or reduction.

Interruptions for Construction, Commissioning, and Facility Testing
5 The ISO will make all reasonable efforts to schedule construction, commissioning, or facility testing activities in conjunction with affected customers planned downtime but may interrupt a customer's system access service to perform such activities.

Customer's Continuing Obligations
6 The customer's obligations to pay any rate, charge, or other amount that has accrued, or is accruing, to the ISO and to fully comply with the ISO tariff are not affected during, or as the result of, any withholding, interruption, limitation, or reduction of system access service as contemplated in this section.

Reasonable Exercise of Discretion
7 Where the ISO, a transmission facility owner, or a customer is granted any discretion pursuant to the ISO tariff (whether with respect to granting its consent or withholding its consent to a particular matter or otherwise), the ISO, the transmission facility owner, and the customer, individually and collectively, will, in every instance, exercise such discretion acting reasonably.

Revision History
2009-10-29 Revised to consolidate and update provisions.
Draft released at stakeholder consultation session.
SECTION 3
CUSTOMER CONNECTION REQUIREMENTS

Transmission Connection Requirements
1 All customers must comply with the transmission connection requirements, obligations, and guidelines related to matters such as, but not limited to, transmission lines, generators, loads, communications, phasor measurement units, protection, revenue metering, supervisory control and data acquisition (SCADA), and transmission data. These requirements, obligations, and guidelines are prepared, published, and may be amended or supplemented by the ISO from time to time. They are provided in the transmission connection requirements section of the ISO website and may be obtained on request from the ISO.

Customer Facilities
2 All customer facilities connecting with the interconnected electric system are the responsibility of the customer. The ISO has no responsibility in respect of service provided over customer facilities.

Use of Transmission Facilities
3 No customer or any other person may rearrange, disconnect, remove, connect with, or otherwise interfere with any transmission facility without the ISO’s prior written consent.

Compliance
4 Failure to comply with the transmission connection requirements, obligations, and guidelines described in subsection 1 above may result in the ISO withholding, suspending, or terminating system access service. Where non-compliance with the transmission connection requirements, obligations, and guidelines would not have a detrimental effect on system reliability, the ISO may, at its sole discretion, waive the compliance requirements for any existing customer for whom, in the ISO’s reasonable opinion, the imposition thereof would create severe hardship or unnecessary costs.

Revision History
2009-11-02 Revised to update provisions.
Draft released at stakeholder consultation session.
SECTION 4
SYSTEM ACCESS SERVICE REQUESTS

Requests for System Access Service

1(1) All requests for new system access services and for changes to existing system access services must be applied for in writing by the customer to the ISO. Separate requests for changes to existing system access services are required at each point of delivery and point of supply at a single transmission substation; applications for net changes will not be accepted.

(2) The ISO will review the service requirements of the customer and determine the appropriate process for providing the system access service.

Requests Which Require Construction of Transmission Facilities

2(1) Where providing system access service requires the construction of transmission facilities, the ISO will determine the connection project scope, assign the project to a transmission facility owner, and confirm the process for developing the connection proposal for the project.

(2) Where construction of transmission facilities is required, the process will include preparation of a connection proposal in accordance with subsection 4 below and preparation of applications in accordance with subsection 5 below.

(3) Throughout the system access service request process, the customer must at all times satisfy the financial obligations required by section 5 of the terms and conditions.

Requests Which Do Not Require Construction of Transmission Facilities

3(1) Where providing system access service does not require the construction of transmission facilities, the ISO will ensure the request can be accommodated on the transmission system and, if so, will proceed to prepare an amended system access service agreement for the customer.

(2) Where construction of transmission facilities is not required, the system access service request may require payment of an amount determined in accordance with section 9 of the terms and conditions.

(3) At the time of execution of the amended system access service agreement by the customer, the ISO will include the amendment in its transmission system model.

Preparation of Connection Proposal

4(1) The customer is responsible for the preparation of the connection proposal including an estimate of project costs. The customer may work with the transmission facility owner or other parties in the development of the connection proposal.

(2) If a loss factor study is required for the project, the ISO will complete one (1) such study at no cost to the customer. Any additional loss factor studies requested by the customer for the project will be completed by the ISO for a fee of $2 500 per study.
(3) Any other studies required to support the connection proposal are the responsibility of the customer. The ISO will provide the customer with ISO information required for the studies.

(4) Upon receipt of a complete connection proposal, including all required studies, the ISO will review the proposal. Any deficiencies identified by the ISO must be addressed by the customer. After the review and correction of deficiencies, if any, the ISO will accept the connection proposal.

(5) The ISO will include the project in its transmission system model upon:
   (a) acceptance of the connection proposal,
   (b) receipt of all required technical data for the connection project, and
   (c) confirmation that the financial obligations of section 5 of the terms and conditions have been met.
   If required, the ISO will also allocate planning capacity to the connection project.

Preparation of Need Identification Documents and Facility Applications

5(1) When the project is included in the ISO’s transmission system model, the ISO will delegate the transmission facility owner to prepare and submit to the ISO a need identification document for the connection project, including completion of any associated participant involvement program required for the need identification document. The ISO will review the need identification document, including the results of any associated participant involvement program, and identify any deficiencies to be addressed by the transmission facility owner. After review and correction of deficiencies, if any, the ISO will endorse the need identification document.

(2) When the project is included in the ISO’s transmission system model, the ISO will direct the transmission facility owner to prepare and submit to the Commission a facility application for the connection project.

(3) The ISO will work cooperatively with the transmission facility owner to ensure all submissions are complete and accurate.

(4) During the preparation of a need identification document or facility application for the connection project, the potential requirement for new or revised ISO rules or operating procedures may be identified. The ISO will address any new or revised ISO rules or operating procedures that are required.

Requirement of Customer to Act

6(1) The ISO, acting reasonably, may establish critical requirements with respect to project completion.

(2) For customers, requirements will include but not be limited to payment of any customer contribution determined under section 8 of the terms and conditions or generating unit owner’s contribution determined under section 10 of the terms and conditions.
If the customer fails to meet the requirements, the ISO may:
(a) cancel, and require the customer to resubmit, the customer’s system access service request;
(b) reassess the inclusion of the project in its transmission system model; or
(c) amend the requirements.

Alternative Processes
At the discretion of the ISO and only with the agreement of the customer, the requirements set out in this section 4 may be satisfied through processes other than those described above. In particular, alternative processes may be utilized for connection projects that materially affect regional transmission system projects.

Resolution of Disputes
Disputes in respect of a system access service request shall be addressed in accordance with section 17 of the terms and conditions.

Revision History
2009-11-02 Revised to reflect draft redesign of system access service request process.
Draft released at stakeholder consultation session.
SECTION 5
FINANCIAL OBLIGATIONS FOR CONNECTION PROJECTS

Amount of Financial Obligation

1(1) The financial obligation of a customer for a connection project is generally illustrated in Figure 5-1 and described more fully below.

(2) A financial obligation exists for a connection project only after the start of development of a connection proposal.

(3) From the start of development of a connection proposal to the ISO’s acceptance of the connection proposal, the financial obligation amount is equal to the total cost, estimated in advance, to be incurred by the transmission facility owner in preparation of the connection proposal.

(4) From the ISO’s acceptance of the connection proposal to the approval of the connection project by the Commission, the financial obligation increases by the amount of all subsequent costs, estimated in advance, to be incurred by the transmission facility owner in preparation of the application or applications required for approval of the connection project.
Section 5

Financial Obligations for Connection Projects

(5) After approval of the connection project by the Commission, the financial obligation increases by monthly amounts equal to the subsequent costs, estimated in advance, to be incurred by the transmission facility owner in construction and completion of the connection project.

(6) Where procurement of long lead time equipment occurs prior to construction of a connection project, all costs associated with such procurement will be added to the financial obligation amounts determined in subsections 1(3) and 1(4) above.

(7) The financial obligation amount will be based on certain assumptions including, but not limited to, the method of construction, the routing of facilities, and the approvals and rights of way required to accommodate the customer’s system access service request. The financial obligation amount may be revised from time to time to reflect changes to:

(a) the system access service request,
(b) the assumptions for the connection project,
(c) variances in the estimated or actual cost of the connection project compared to the original estimate, or
(d) other relevant factors.

(8) The total amount of financial obligation will not exceed the estimated total cost of the connection project, as revised from time to time, including, but not limited to, costs incurred by the transmission facility owner in preparation of the connection proposal, preparation of required applications, and construction of the project.

Form and Provision of Financial Security

2(1) Distribution facility owners that are regulated by the Commission are not required to provide financial security for connection projects. All other customers must provide security for connection projects in accordance with this subsection 2.

(2) Financial security must be provided by the customer to the transmission facility owner, in the amount of and at the time defined for the financial obligations described in subsection 1 above, up to the maximum local investment determined for the connection project under section 8 of the terms and conditions.

(3) Security must be in the form of a guarantee, cash deposit, or irrevocable letter of credit from a Canadian chartered bank, credit union, trust company, or other financial institution with a minimum senior unsecured long-term debt A– credit rating or equivalent as determined by Standard & Poor’s, Moody’s Investor Services, DBRS, or equivalent credit rating agency. The security must be satisfactory to the transmission facility owner in form, substance, and amount, at the transmission facility owner’s sole discretion which will be reasonably exercised.

(4) Unsecured credit established for a customer by the ISO may be used to reduce the amount of security the customer must provide to the transmission facility owner for the connection project, up to the limit of such unsecured credit not utilized to reduce other security required by the ISO or the transmission facility owner.
(5) The customer may provide security in amounts greater than the financial obligations described in subsection 1 above, at the customer’s sole discretion. Provision of additional security does not reduce the payment of customer contribution required by subsection 3 below.

Form and Provision of Customer Contribution

3(1) A financial obligation described in subsection 1 above may exceed the maximum local investment determined for the connection project under section 8 of the terms and conditions. If so, the amount of the financial obligation above the maximum local investment must be paid by the customer as a customer contribution. The customer contribution must be paid in the amount in excess of the maximum local investment and at the time defined for the financial obligations described in subsection 1 above.

3(2) The customer contribution must be paid by way of electronic funds transfer or wire transfer to the bank account specified by the transmission facility owner.

3(3) The customer may provide the customer contribution in amounts greater than the financial obligations described in subsection 1 above, at the customer’s sole discretion.

Cancellation

4(1) If a connection project is cancelled at any time prior to commercial operation, the customer must pay all costs incurred or required to be incurred by the transmission facility owner in the preparation of the connection proposal, preparation of required applications, and construction of the project. The customer must also pay any other costs incurred or required to be incurred by the transmission facility owner with respect to the project, including, but not limited to, all cancellation costs, penalties, and costs for material salvage and reclamation of the construction site. If the customer fails to make payment on the payment due date, the transmission facility owner at its discretion and without further notice may realize on any security provided to the transmission facility owner by the customer.

4(2) If a customer takes action that indicates it has terminated or abandoned its intention to proceed to commercial operation of the connection project, the project will be deemed to be cancelled pursuant to subsection 4(1) above.

4(3) The ISO may, but is not required to, deduct any amounts owing by the ISO to the customer under any agreement between the ISO and the customer on partial or full (as the case may be) satisfaction of such costs, penalties, or other claims. Such amounts may include, but are not limited to, debts, liquidated demands, unliquidated demands, damages, or other obligations.

Release of Security

5 Within ninety (90) days after commercial operation of the connection project, any security held for the connection project will be returned to the customer. For additional clarity, a customer contribution required by subsection 3 above will not be returned to the customer.
Compliance

6(1) A request for security or customer contribution, or for additional or replacement security or customer contribution, must be satisfied by the customer within two (2) business days of such request.

(2) Customers must report any event of default for borrowed funds or material adverse changes in their financial position within two (2) business days of such event.

(3) If the customer fails to provide security or customer contribution as requested under subsection 6(1) above or fails to report an event or change under subsection 6(2) above, all work related to the connection project will cease. Work on the project will remain suspended until the required security or contribution is provided or the financial position of the customer is reassessed. If the project remains suspended, the customer may fail to meet critical requirements under section 4 of the terms and conditions, resulting in cancellation of the system access service request or reassessment of the inclusion of the project in the ISO’s transmission system model.

(4) Any such cessation or suspension of work on the project under subsection 6(3) above will not relieve the customer from its financial obligation for amounts that have accrued, or are accruing, to the ISO or the transmission facility owner with respect to the connection project.

Revision History

2009-10-27 Revised to update financial obligation requirements.
Draft released at stakeholder consultation session.
SECTION 6
METERING

Measurement System Standard

1. All customers must comply with applicable provisions of the AESO Measurement System Standard as prepared, published, and amended or supplemented by the ISO from time to time. Without limiting the generality of the foregoing, all metering equipment provided by a customer must at all times comply with the AESO Measurement System Standard. The AESO Measurement System Standard is provided in the transmission connection requirements section of the ISO website and may be obtained on request from the ISO.

Requirement to Install Metering

2. The ISO may require the customer to install metering equipment on the customer’s premises, at the customer’s sole cost. If the customer fails to comply with such requirement in a timely manner, the ISO may, at the customer’s sole cost, direct the transmission facility owner to enter and install metering equipment on the customer’s premises.

Revision History

2009-10-29 Revised to reflect draft redesign of system access service request process. Draft released at stakeholder consultation session.
SECTION 7
PROVISION OF INFORMATION BY CUSTOMERS

System Access Information
1 Customers must provide, upon request, all information that the ISO requires in order to discharge its duties and functions under the Act or in compliance with any external agency’s reporting requirements. Such information includes, but is not limited to:
   (a) information required by the ISO in respect of new or expanding system access service; and
   (b) technical information during construction and prior to energization, including pre-commissioning information requirements which may be obtained from the ISO.

Operating and Forecast Information
2(1) From time to time, but generally not more than once in a 12-month period, the ISO may request a customer to provide any or all of the following information:
   (a) a copy of the customer’s operating procedures;
   (b) a schedule of planned or maintenance outages for the following two calendar years; or
   (c) forecast information for the following five years, including:
      (i) forecast maximum contract capacity by point of delivery or point of supply by month,
      (ii) the location and size of any new point of delivery and point of supply required, and
      (iii) the name and location of any existing point of delivery or point of supply which may no longer be required.

(2) The appropriate forms for provision of forecast and update information will be provided by the ISO.

Effect of Non-Compliance
3(1) Failure to provide information that may have an impact on safety or system security will result in suspension, termination, or delay of system access service until such time that the information is provided to the ISO.

(2) The ISO is not responsible for any delay, interruption, damage, or other problems caused by a delay in the provision of information required from a customer.

Revision History
2009-09-29 Revised to reflect draft redesign of system access service request process. Draft released at stakeholder consultation session.
SECTION 8
CUSTOMER CONTRIBUTIONS FOR CONNECTION PROJECTS

Connection Costs

1 The costs of a connection project are those costs reasonably associated with facilities that:
   (a) will be owned and operated by a transmission facility owner;
   (b) are required to provide system access service to a new point of connection or to increase the capacity of or improve system access service to an existing point of connection; and
   (c) are reasonably required to meet the demand and supply forecast of the customer and the customer's reliability and operating requirements.

Classification of Customer-Related and System-Related Costs

2(1) All costs associated with a connection project will be classified as either customer-related or system-related.

(2) Customer-related costs are those costs related to a contiguous connection project including, but not limited to, the connection substation, any radial transmission extensions to the substation, and modifications at existing adjacent substations. In particular, customer-related costs will include costs associated with:
   (a) the point of connection;
   (b) new radial transmission line with only one transmission source;
   (c) a share of existing facilities for which another customer previously paid a customer contribution within the past twenty (20) years, based on:
      (i) the shared facilities being used for system access service to the new customer,
      (ii) the higher of any Rate DTS or Rate STS contract capacity for each customer, and
      (iii) the contract capacity levels reasonably expected over twenty (20) years following the previous customer's connection;
   (d) line moves or burials of existing transmission line;
   (e) communication at the point of connection;
   (f) communication enhancements at the nearest existing substations with communications equipment;
   (g) breakers and associated equipment at an existing substation, if required;
   (h) special protection schemes and remedial action schemes, if required;
   (i) the advancement of transmission facilities included as part of a critical transmission development or regional transmission system project under subsection 2(3)(e) below, calculated as the difference between the present values of the capital costs of the advanced and as-planned facilities using the discount rate provided in subsection 10 below;
(j) facilities previously classified as system-related under subsection 3(3)(f) below and now reclassified as customer-related to meet the requirements of the connection project; and

(k) other facilities required to complete the customer’s connection, including facilities of the transmission facility owner required to enable the customer to meet all relevant technical requirements for the connection.

(3) System-related costs are those costs related to a connection project including, but not limited to, non-contiguous components of the project and any looped transmission facilities. In particular, system-related costs will include costs associated with:

(a) looped transmission facilities, which are facilities that increase the number of electrical paths between any two (2) points of connection (excluding the point of connection serving the customer) and which exclude any new radial transmission line;

(b) converting existing transmission or distribution lines to an underbuilt configuration on new transmission facilities;

(c) installation of capacitor banks to reduce transmission voltage drop caused by inductive or reactive loads;

(d) shunt reactors to lower voltage on long transmission lines;

(e) transmission facilities included as part of a critical transmission development or regional transmission system project:
   (i) in the ISO’s most recent long-term transmission system plan,
   (ii) in a need identification document filed with the Commission, or
   (iii) as reasonably expected by the ISO to be required in the future; and

(f) facilities in excess of the minimum size required to serve the customer where, in the opinion of the ISO, economics or system planning support the development of such facilities.

Facilities in Excess of Good Utility Practice

3(1) Any customer-related costs of facilities which are deemed, in the opinion of the transmission facility owner, to be in excess of those required by good utility practice must be wholly paid by the customer as part of the customer contribution.

(2) Good utility practice as used in subsection 3(1) above means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region and consistently adhered to by the transmission facility owner.
Valuation of Facilities for Contribution Determination

4(1) Equipment used for a connection project will generally be valued at replacement cost new.

(2) Where a connection project involves the installation of a transformer as a replacement for a smaller transformer which is removed from service at a substation:
   (a) when the transformer which is removed is either:
      (i) deemed re-deployable for use at another substation,
      (ii) deemed suitable for use as an operating spare, or
      (iii) treated as a capital maintenance cost
      by the transmission facility owner, then the customer-related costs for the connection project shall be reduced by the replacement cost new of the removed transformer; or
   (b) in all other cases, including when the transformer which is removed is scrapped without being treated as a capital maintenance cost by the transmission facility owner, there will be no such reduction to the customer-related costs for the connection project.

(3) Replacement cost new as used in subsections 4(1) and 4(2) above means the current cost of similar new equipment having the nearest equivalent capability to the equipment being valued.

Allocation of Costs at Substations Serving Multiple Customers

5(1) Customer-related costs associated with facilities used to provide service to multiple customers at a single substation will be allocated among those customers. The multiple customers at the substation may be solely Rate DTS customers, solely Rate STS customers, or a combination of both.

(2) To allocate the costs, the customer-related costs in subsection 5(1) above will be multiplied by the substation fraction for each customer.

(3) Costs allocated to a customer taking service under Rate DTS are deemed to be demand-related costs.

(4) Costs allocated to a customer taking service under Rate STS are deemed to be supply-related costs.

Application of Contribution Policy

6(1) The customer contribution will be calculated in accordance with the customer contribution policy described in the terms and conditions of the ISO in effect on the date on which the Commission grants permit and license for the connection project.

(2) Customer contribution amounts must be paid by the customer to the transmission facility owner in accordance with the financial obligation provisions of section 5 of the terms and conditions.
(3) For a **customer** taking service under Rate DTS, the **customer** contribution is the demand-related costs less the local investment determined under subsection 7 below.

(4) For a **customer** taking service under Rate STS, the **customer** contribution is equal to the supply-related costs. In addition, an STS **customer** must pay to the ISO any **generating unit owner**'s contribution required under section 10 of the terms and conditions.

(5) For a **customer** taking service under any rate other than Rate DTS or Rate STS, the **customer** contribution is equal to all **customer**-related costs.

### Determination of Local Investment

7(1) For a **customer** taking service under Rate DTS, the maximum local investment will be based on the contract capacity and investment term for the connection project.

(2) The contract capacity used for the local investment calculation shall not include any capacity transferred from another **point of delivery**.

(3) The investment term must be from five (5) to twenty (20) years inclusive.

(4) For a connection project for a new **point of delivery**, the maximum local investment will be calculated using the table below as the sum, for each tier, of:

- (a) the **substation fraction** or **contract capacity**, as appropriate, from column A,
- (b) multiplied by the investment amounts from column B or column C, as applicable,
- (c) multiplied by the investment term in years.

<table>
<thead>
<tr>
<th>Column A</th>
<th>Column B</th>
<th>Column C</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tier</strong></td>
<td>Investment for Service Under Rate DTS</td>
<td>Investment for Service Under Rate PSC</td>
</tr>
<tr>
<td><strong>Substation fraction (for new points of delivery only)</strong></td>
<td>$53 350/year</td>
<td>$11 740/year</td>
</tr>
<tr>
<td>First (7.5 × <strong>substation fraction</strong>) MW of contract capacity</td>
<td>$37 370/MW/year</td>
<td>$8 220/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × <strong>substation fraction</strong>) MW of contract capacity</td>
<td>$13 960/MW/year</td>
<td>$3 070/MW/year</td>
</tr>
<tr>
<td>Next (23 × <strong>substation fraction</strong>) MW of contract capacity</td>
<td>$8 490/MW/year</td>
<td>$1 870/MW/year</td>
</tr>
<tr>
<td>All remaining MW of <strong>contract capacity</strong></td>
<td>$4 650/MW/year</td>
<td>$0/MW/year</td>
</tr>
</tbody>
</table>

(5) For a connection project at an existing **point of delivery** to accommodate a **contract capacity** increase:

- (a) the **contract capacity** used for the local investment calculation shall be the capacity increase contracted by the **customer** since the most recent change in customer contribution at the point of delivery;
Section 8
Customer Contributions for Connection Projects

(b) the substation fraction will be calculated based on contract capacities after the increase;

(c) the existing contract capacity establishes the tier in which investment will become available for the incremental contract capacity; and

(d) where the sum of existing and incremental contract capacities exceeds the remaining MW in the tier, investment will become available from subsequent tiers, as appropriate.

(6) Where a customer contracts for increases or decreases to capacity over the investment term for a connection project, the investment will be calculated using the capacities that have been contracted for each year of the investment term.

(7) The maximum local investment calculated in subsection 7(4) or 7(5) above will not exceed the demand-related costs.

Operations and Maintenance

8 For customers taking service under Rate DTS, an operations and maintenance charge of 14% will be added to the amount of demand-related costs which exceed the local investment determined in subsection 7 above.

Limitations

9 The ISO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of the foregoing, this discretion includes the determination of costs to be system-related in certain circumstances that might, under strict application of the contribution policy, have been classified as customer-related.

Discount Rate

10 The discount rate applicable in the calculation of customer contributions under this section 8 of the terms and conditions and payments in lieu of notice under section 9 of the terms and conditions will be determined as follows:

(a) in areas operated by an investor-owned transmission facility owner or by an income tax paying municipally-owned transmission facility owner:

\[0.67 \times (\text{GCB} + 1\%) + [(0.33 \times \text{R}) + (1-T)]\]

where GCB is equal to the yield on 30-year Government of Canada bonds; R is equal to the Commission-approved generic rate of return on common equity, as amended from time to time; and T is equal to the combined federal and provincial income tax rate for an investor-owned transmission facility owner.

(b) in areas operated by a non-income tax paying municipally-owned transmission facility owner:

the yield on 30-year Government of Canada bonds plus 1.9%. 
Miscellaneous

11(1)  Where relocation of transmission facilities is required, the ISO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the party causing the relocation.

(2)    Where new facilities between adjacent control areas are required, the cost of such facilities will be shared between the ISO and the party responsible for costs in the other control area based on the extent that each benefits directly from the facilities.

Revision History
2009-11-02  Revised to update contribution policy.
             Draft released at stakeholder consultation session.
SECTION 9
CHANGES TO SYSTEM ACCESS SERVICE AFTER ENERGIZATION

Events Resulting in Adjustments to Customer Contributions

1(1) Certain events may, in the ISO’s sole opinion, result in an adjustment to the customer contribution determined by application of the ISO’s customer contribution policy to a connection project.

(2) The events which may result in contribution adjustments include, but are not limited to:
   (a) a customer materially increasing or decreasing contract capacity or investment term, or terminating a system access service agreement, prior to the expiry of the investment term for a connection project;
   (b) one or more additional customers using facilities originally installed for an existing customer or customers, resulting in sharing of facilities as provided for in subsection 2 below;
   (c) facilities previously classified as system-related being reclassified as customer-related to meet changes in customer requirements;
   (d) facilities previously classified as customer-related being reclassified as system-related;
   (e) a material error in the original customer contribution determination;
   (f) a material variance in the estimated or actual cost of the connection project compared to the original estimate; or
   (g) a material reduction to the period of advancement of transmission facilities included as part of a critical transmission development or regional transmission system project under the provisions of subsection 2(2)(i) of section 8 of the terms and conditions.

(3) The customer, the ISO, or the transmission facility owner may initiate an adjustment to a customer contribution as a result of an event described in subsection 1(2) above.

(4) No adjustments to customer contributions will be made more than twenty (20) years after construction of a connection project.

(5) Where an event requires the addition of new equipment at an existing point of connection, the customer contribution will be determined under the provisions of section 8 of the terms and conditions rather than this section 9.

Shared Facilities

2(1) If the ISO installs facilities to serve a customer that is required to pay a customer contribution, and then uses those facilities to serve other customers within twenty (20) years after construction of a connection project, the ISO will adjust the original customer’s contribution and assess each of the new customers a contribution based on:
   (a) the shared facilities being used for system access service to the new customer,
   (b) the higher of any Rate DTS or Rate STS contract capacity for each customer, and
(c) the contract capacity levels reasonably expected over twenty (20) years following the first customer’s connection.

(2) The cost of the shared facilities will be allocated between the customers by:
(a) determining the higher of any Rate DTS or Rate STS contract capacity for each customer in each of the twenty (20) years following construction of the original connection project, assigning a contract capacity of zero (0) in any year in which a customer did not receive system access service;
(b) calculating the percentage share of the facilities attributable to each customer by dividing the contract capacity determined in subsection 2(2)(a) above for the customer in a year by the sum of contract capacities for all sharing customers in the year; and
(c) calculating the average percentage share over the full twenty (20) year period for each customer.

The average percentage determined in subsection 2(2)(c) above will be used to allocate the costs of shared facilities among the customers.

Application of Contribution Policy

3(1) For an adjustment to a customer contribution paid for a connection project, the adjustment will be determined in accordance with the customer contribution policy described in the terms and conditions of the ISO as applied to the transmission facilities when constructed.

(2) The ISO will determine the amount of any adjustments to contributions. Such adjustments will be paid by the customer to the transmission facility owner, or will be refunded by the transmission facility owner to the customer.

(3) Adjustments are charged or refunded without interest.

(4) Adjustments will be neither charged nor refunded for amounts less than $10 000.

Notices for Reductions or Terminations of Contract Capacity

4(1) Reductions or terminations of contract capacity will be effective five (5) years after the date of the request for reduction or termination.

(2) A customer reducing or terminating a system access service agreement may choose to make a lump sum payment determined by the ISO in lieu of the 5-year notice period in subsection 4(1) above. The payment in lieu of notice reflects a share of system costs potentially incurred to reasonably accommodate the customer’s contract capacity over the 5-year planning horizon of the transmission system.

(3) The lump sum payment in lieu of notice will be:
(a) for customers reducing or terminating a service under Rate DTS, the present value of the difference in bulk system and local system charges which would be attributed to the service with and without the reduction or termination of contract capacity during the notice period; or
(b) for customers terminating a service under Rate STS for a regulated generating unit listed in Appendix C of the ISO tariff, the difference in regulated generating unit
connection cost charges which would be attributable to the service with and without
the termination of the service during the notice period.

(4) The discount rate used in the present value calculation will be that provided in
subsection 10 of section 8 of the terms and conditions.

(5) Payment in lieu of notice may be made at any time prior to or during the 5-year notice
period, for the remainder of the notice period. Payment must be received by the ISO at
least thirty (30) days before the reduction or termination of contract capacity is effective.

(6) If circumstances warrant, the ISO may waive or reduce the requirement for payment in
lieu of notice in recognition of transmission system benefits arising from the reduction or
termination of contract capacity. Those benefits may include, but are not limited to, relief
of regional transmission constraints, removal of capacity limitations which would restrict
system access service to other customers, or avoidance of future upgrades to the
transmission system.

(7) The ISO may re-assess the payment in lieu of notice if material differences arise
between the requested and actual contract capacities or between expected and actual
load, and require additional payment from the customer if appropriate.

Excursions During the Notice Period
5(1) The contract capacity immediately following the 5-year notice period required by
subsection 4(1) above will be the maximum of:
(a) the pre-notice contract capacity less the reduction of contract capacity requested
by the customer; or
(b) the highest metered demand during the 5-year notice period less the reduction of
contract capacity requested by the customer.

(2) A customer may provide an additional notice of reduction after an excursion to request
a subsequent reduction of contract capacity to the original notice level.

Payments
6(1) A request for payment of a customer contribution adjustment or a payment in lieu of
notice must be satisfied by the customer within two (2) business days of such request.

(2) The amount must be paid by way of electronic funds transfer or wire transfer to the bank
account specified:
(a) for a customer contribution adjustment, by the transmission facility owner; or
(b) for a payment in lieu of notice, by the ISO.

Revision History
2009-11-02 Revised to update contribution policy.
Draft released at stakeholder consultation session.
SECTION 10
GENERATING UNIT OWNER’S CONTRIBUTION

Maximum STS Contract Capacity

1 The contract capacity for a new point of supply established by the ISO may not exceed:
   (a) the sum of the maximum capabilities of all generating units connected to the interconnected electric system by the point of supply, less
   (b) the sum of all loads that offset the energy delivered to the interconnected electric system from that point of supply under normal operating conditions.

Determination of Generating Unit Owner’s Contribution

2(1) In addition to the customer contribution determined in section 8 of the terms and conditions, a customer taking system access service under Rate STS is required to pay a generating unit owner’s contribution for:
   (a) new Rate STS capacity requirements at a new point of supply, and
   (b) new Rate STS capacity requirements at an existing point of supply where such additional requirements are the result of the addition of a new generating unit.

(2) The generating unit owner’s contribution is the sum of the following:
   (a) $10 000/MW multiplied by the amount of new Rate STS contract capacity, plus
   (b) $40 000/MW multiplied by the amount of new Rate STS contract capacity multiplied by the customer’s generating unit owner’s contribution factor. Generating unit owner’s contribution factors will be determined by the ISO for areas of the transmission system where generation exceeds load in accordance with section 29 of the Transmission Regulation, and will be made publicly available by the ISO in advance of their effective dates.

(3) Generating unit owner’s contributions are not required for Rate STS capacity requirements for which a system access service agreement was signed before January 1, 2006, or for Rate STS capacity requirements of 1 MW or less.

Payment of Generating Unit Owner’s Contribution

3(1) The generating unit owner’s contribution must be paid in full by the customer to the ISO at least 30 days prior to the energization of the generating unit.

(2) The generating unit owner’s contribution must be paid by way of electronic funds transfer or wire transfer to the bank account specified by the ISO.

Refund of Generating Unit Owner’s Contribution

4(1) A customer’s generating unit owner’s 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 subsection 4.

(2) The generating unit owner’s contribution will be refunded in annual amounts during the refund period which begins on January 1 following the commercial operation date of
the customer’s generating unit and ends nine (9) calendar years later on December 31.

(3) The annual amounts during the refund period will be:
   (a) 5.6% of the generating unit owner’s contribution in each of the first through fourth calendar years in the refund period;
   (b) 11.2% of the generating unit owner’s contribution in the fifth calendar year in the refund period; and
   (c) 16.6% of the generating unit owner’s contribution in each of the sixth through ninth calendar years in the refund period.

(4) 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 subsection 4(3) above for that year. If the ISO rules regarding satisfactory annual performance are not met, the annual amount for that year will be reduced or forfeited.

(5) For each year of the refund period, the customer must report the generating unit’s annual performance to the ISO by January 31 of the following year.

(6) 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 ISO will pay the generating unit owner’s contribution refund annual amount to the customer by February 28 of the following year.

(7) Annual amounts are refunded without interest.

Return of Refunds

5 The ISO may determine that a refund of an annual amount must be returned to the ISO in whole or in part where it is demonstrated that an error was made or that an inappropriate refund was given.

Revision History

2009-11-02 Revised to update generating unit owner’s contribution policy.
Draft released at stakeholder consultation session.
SECTION 11  
ANCILLARY SERVICES

General

1  Ancillary services are provided by customers when the ISO determines there is a need for such services to maintain system security and ensure the reliable operation of the interconnected electric system. Customers required by the ISO to provide ancillary services shall be directed to do so in accordance with ISO rules and will be compensated as provided in subsections 2 through 7 below, as applicable.

Contracted Ancillary Services

2  If at the time the customer is directed to provide ancillary services the customer has an existing contract with the ISO to provide the ancillary services in question from the directed facility (the "existing contract"), then the amount to be paid to the customer by the ISO for the ancillary services shall be determined according to the terms of the existing contract.

Directed Ancillary Services Other Than Transmission Must-Run Services

3  If at the time the customer is directed to provide an ancillary service other than transmission must-run service, the customer does not have an existing contract, then the amount to be paid to the customer by the ISO in respect of each ancillary service provided shall be the greater of the following monthly amounts. Each amount is the sum for the month of hourly compensation amounts.

(a) The product of the MW hour directed and the highest price paid in the hour to customers providing the same ancillary service pursuant to subsection 2 above and that the existing contract was the result of a competitive process conducted in the prior twelve (12) months; or

(b) The verifiable net opportunity cost related to foregone electricity sales incurred by the customer to supply the directed ancillary service, taking into account offsetting pool energy receipts.

Transmission Must-Run Services

4(1) Transmission must-run services are ancillary services provided by customers with generating units in response to a direction provided by the ISO to ensure safe and reliable electrical service for a region of the interconnected electric system.

(2) Transmission must-run services are foreseeable if the ISO, taking into account reasonable procurement timing requirements, determines transmission must-run services are required to meet ISO transmission reliability criteria which includes consideration of expected operating conditions and planned transmission outages. Transmission must-run services are unforeseeable transmission must-run services if they do not constitute foreseeable transmission must-run services.
Arrangements and Compensation for Foreseeable TMR Services

5 Arrangements and compensation for foreseeable transmission must-run services will be made in accordance with the *Foreseeable TMR Service Procurement Procedure* (Appendix B of the *ISO tariff*).

Compensation for Unforeseeable Transmission Must-Run Services

6(1) If at the time the customer is directed to provide unforeseeable transmission must-run service the customer does not have an existing contract, then the amount to be paid to the customer in the applicable billing period for unforeseeable transmission must-run service is equal to variable costs plus fixed costs, where:

(a) variable costs means the hourly difference of the pool price subtracted from the energy price, which shall not be less than zero (0), multiplied by the corresponding hourly energy generated (MWh) by the specific directed generating unit in compliance with the directive to provide unforeseeable transmission must-run service, where:

(i) Energy price ($/MWh) is the product of the heat rate multiplied by the fuel cost, added to the sum of the variable STS charges and variable O&M charge.

(ii) Heat rate (GJ/MWh) is the actual heat rate of the customer’s generating unit during the period when the unit was complying with the directive.

(iii) Fuel cost for a gas generating unit is the natural gas market price ($/GJ), being the “Daily Spot Price at AECO-C and NIT”, excluding weekends, as published in the *Canadian Gas Price Reporter*, for natural gas on the applicable day. The fuel cost for a coal generating unit shall be provided by the customer.

(iv) Variable STS charges ($/MWh) is the actual cost of all variable charges from Rate STS of the *ISO tariff*, including the applicable loss factor charge or credit.

(v) Variable O&M charge ($/MWh) is the all-in cost (including major/minor overhauls), fixed at $4.00/MWh, of providing incremental output from the unit, excluding fuel costs and variable STS charges.

(b) Fixed costs are equal to the average monthly fixed cost multiplied by the greater of the must-run ratio or the minimum must-run ratio, where:

(i) Average monthly fixed cost is equal to one-twelfth of the sum of the annual costs in items (A) through (H) as follows:

(A) annual amortization and depreciation amounts for the customer’s investment or for the power purchase arrangement acquisition cost related to the specific directed generating unit, consistent with amounts reported in the customer’s audited financial statements, and adjusted for cogeneration infrastructure not utilized for generation purposes;

(B) the product of the unamortized or undepreciated capital investment multiplied by a deemed debt percentage of 70% and multiplied by a debt interest rate that is equal to the current 10-year Government of Canada bond interest rate plus 0.5%, and where the unamortized or undepreciated capital investment is the greater of
Section 10
Generating Unit Owner’s Contribution

(1) the customer’s initial cost of property, plant, and equipment for the specific directed generating unit, or the customer’s initial power purchase arrangement acquisition cost related to the specific directed generating unit, less accumulated depreciation or amortization, as the case may be, related to the specific directed generating unit; or

(2) 25% of the customer’s initial cost of property, plant, and equipment for the specific directed generating unit, or the customer’s initial power purchase arrangement acquisition cost related to the specific directed power purchase arrangement.

(C) the product of unamortized or undepreciated capital investment, as described in (B) above, multiplied by a deemed 30% common equity percentage of capital structure multiplied by a deemed 12% rate of return on equity;

(D) if the customer provides verifiable actual values for the items in both (B) and (C) then those will be used instead of the deemed values;

(E) the product of the tax rates multiplied by the rate of return on equity amount determined in (C), where income tax costs reflect the marginal income tax rates for both federal and provincial portions of income tax;

(F) total annual direct fixed operation and maintenance costs associated with the specific directed generating unit;

(G) total annual direct fixed fuel costs associated with the specific directed generating unit;

(H) fixed charges from applicable PPAs associated with the specific directed generating unit.

(ii) Must-run ratio is the ratio of the number of hours in the month when unforeseeable transmission must-run services were provided to the total number of hours in the month;

(iii) Minimum must-run ratio is:

(A) 12% for the first or second unforeseeable transmission must-run service event within a rolling 12-month period in which transmission must-run service is directed by the ISO;

(B) 20% for the third unforeseeable transmission must-run service event within a rolling 12-month period in which transmission must-run service is directed by the ISO;

(C) 30% for the fourth unforeseeable transmission must-run service event within a rolling 12-month period in which transmission must-run service is directed by the ISO;

(D) 40% for the fifth unforeseeable transmission must-run service event within a rolling 12-month period in which transmission must-run service is directed by the ISO; or

(E) 50% for the sixth or any additional unforeseeable transmission must-run service event within a rolling 12-month period in which transmission must-run service is directed by the ISO.
If there is more than one unforeseeable transmission must-run service event in a billing period, the minimum must-run ratio shall be the highest applicable percentage described in (A) through (E) above.

(2) In lieu of the variable and fixed costs in subsections 6(1)(a) and 6(1)(b) above, if a customer can demonstrate foregone future energy sales due to a transmission must-run directive, then the verifiable net opportunity cost related to foregone electricity sales incurred by the customer to supply the directed transmission must-run service, taking into account offsetting pool energy receipts. This applies only to customers that have responded to a transmission must-run direction using hydroelectric generating units.

Maximum TMR Services Compensation

7 The maximum monthly amount to be paid by the ISO for transmission must-run service results in the recovery of fixed, operating, and maintenance costs, including a reasonable rate of return for the service provider, and is equal to the average monthly fixed cost plus variable costs as provided for in subsection 6 above.

Invoicing

8 Customers that provide unforeseeable transmission must-run service in response to a direction from the ISO will submit an invoice to the ISO within fifteen (15) business days after the end of the month in which the service was provided. The amount of the invoice shall be determined in accordance with the method in subsection 6 above, and will separately itemize the values used for each component specified (fixed and variable costs).

Audit Rights

9 The ISO has the right to audit a customer's invoices and source information related thereto for transmission must-run services, provided that any such audit is:
   (a) conducted only on reasonable prior notice to the customer;
   (b) conducted on the customer's premises during normal business hours;
   (c) not conducted by, or the information gathered made available to, those persons at the ISO that determine contestability for purposes of the ISO procuring transmission must-run competitively;
   (d) conducted subject to section 16 of the terms and conditions; and that
   (e) no copies of records reviewed during the audit shall be made without the customer's prior written consent.

Revision History

2009-11-02 Reformatted for consistency with revised terms and conditions. Draft released at stakeholder consultation session.
SECTION 12
DEMAND OPPORTUNITY SERVICE

[Note: Will be revised to consolidate and incorporate rights and obligations from existing OPPs and DOS Business Practices.]

Eligibility

1 To qualify for demand opportunity service, the customer must meet the commercial eligibility criteria and submit the required applications as set out in the Demand Opportunity Service Business Practices. The ISO must be satisfied that the customer’s use of the demand opportunity service would not proceed on any other applicable rate. Eligibility is also contingent upon sufficient transmission capacity and suitable system operation conditions capable of accommodating the request.

Fees

2 In conjunction with the demand opportunity service stage 2 application, which must be submitted at least thirty (30) days prior to taking demand opportunity service, the customer must pay a non-refundable $5 000 fee to the ISO for evaluation of the customer’s commercial eligibility for demand opportunity service.

Recallable Service

3 Demand opportunity service is recallable:
   (a) in accordance with the provisions of Rate DOS;
   (b) in accordance with the provisions of section 2 of the terms and conditions; and
   (c) whenever sufficient transmission system capacity becomes temporarily or permanently unavailable.

Metered Energy

4 Any metered energy taken by the customer in a billing period that exceeds the aggregate metered energy allowed under the customer’s demand opportunity service system access service agreements will be added to the customer’s Rate DTS metered energy in the same billing period. Where the customer has not executed a system access service agreement for Rate DTS, the customer will be deemed to have executed such an agreement effective with the beginning of the relevant billing period.

Effect of Disqualification

5 From time to time, the ISO may audit the customer’s eligibility for demand opportunity service. If the ISO finds that the customer no longer qualifies for demand opportunity service, the customer will be deemed to have executed an agreement for demand transmission service effective on the date of disqualification and the ISO will terminate billing under Rate DOS. The ISO may, in its sole discretion, recover retroactive amounts for the period during which such customer did not qualify for, but was billed under, Rate DOS.
Revision History

2009-11-02  Revised to update generating unit owner’s contribution policy.
            Draft released at stakeholder consultation session.
SECTION 13
FINANCIAL SECURITY, BILLING, AND PAYMENT TERMS

Credit Requirements

1(1) Distribution facility owners that are regulated by the Commission are not required to comply with the ISO's financial security requirements applicable to system access service charges in this section 13 of the terms and conditions. All other customers must comply with the ISO's financial security requirements.

(2) Prior to receiving service, the customer must provide the ISO with all financial information that the ISO reasonably requests in order to establish the financial security required from the customer.

(3) If requested by the ISO, the customer must provide financial security in an amount of up to two (2) months’ payment in advance for system access service. The amount of the financial security will be estimated by the ISO at its sole discretion based on the customer’s historic use or on an estimate where actual use is not available. Such security must be in a form satisfactory to the ISO including but not limited to a guarantee, cash deposit, or irrevocable letter of credit from a Canadian chartered bank, credit union, trust company, or other financial institution with a minimum senior unsecured long-term debt A– credit rating or equivalent as determined by Standard & Poor’s, Moody’s Investor Services, DBRS, or equivalent credit rating agency.

(4) The ISO may request, at its sole discretion, at any time after initial granting of service, additional or replacement security based on the ISO’s estimate of the appropriate security required. Required additional or replacement security must be provided to the ISO within two (2) business days of such request. Customers must report any event of default for borrowed funds or material adverse changes in their financial position to the ISO within two (2) business days of such event.

(5) Unsecured credit established for a customer by the ISO may be used to reduce the amount of security the customer must provide, up to the limit of such unsecured credit not utilized to reduce other security required by the ISO or the transmission facility owner.

Effect of Non-Compliance

2(1) If the customer fails to provide adequate security outlined in subsection 1 above, then subsection 2(1)(a), 2(1)(b), or both below may apply.

   (a) The ISO, at its sole discretion, may invoke a financial penalty which will be calculated at the Toronto Dominion Canadian prime rate plus 6%; until such time as the security has been provided to the ISO.

   (b) The ISO may immediately withhold or suspend the customer’s system access service.

(2) Any withholding or suspension of system access service under subsection 2(1)(b) above will not relieve the customer from its obligation to pay any rate, charge, or other amount that has accrued, or is accruing, to the ISO.
Billing Procedures

3(1) The ISO issues statements of account which may include:

(a) amounts determined on an initial basis in the month following energy flow and no later than fifteen (15) business days after the end of the billing period;

(b) amounts determined on an interim basis in the third month following energy flow; and

(c) amounts determined on a final basis in the seventh month following energy flow.

(2) From time to time the ISO may review a statement of account issued in accordance with subsection 3(1) above and may issue a new statement of account following that review.

(3) The ISO may choose not to issue statements of account on an interim or final basis that result in a charge or refund of less than $1,000.

(4) The ISO may use estimated values to produce a statement of account when metered demand or metered energy data is not available or is incomplete, when metering equipment fails, or when the data is under dispute. The ISO may also use estimated values to produce a statement of account if the ISO’s billing and settlement system is unable to produce a statement of account. In the event that a statement of account is based on estimated values, an adjustment will be made on a subsequent statement of account issued in accordance with subsection 3(1)(a) or 3(1)(b) above to reflect the use of actual or more appropriate estimated values.

(5) The ISO may, but is not required to, deduct from the statements of account any amounts owing by the ISO to the customer or its affiliates.

Totalized Billing

4 Effective January 1, 2002, where a customer is an industrial facility with multiple points of connection, the ISO may totalize the points of connection and produce one statement of account for the customer. The ISO will base its decision to totalize on a review of the economics of providing more than one point of connection, reclassification of the site as a Commission-designated industrial system, or the existence of a credible transmission bypass alternative.

Adjustments

5 When a customer requests that a statement of account issued in accordance with subsection 3 above be recalculated and reissued forty-five (45) days or more after the end of the applicable billing period as a result of:

(a) unavailable or incomplete meter data, or

(b) inaccurate estimates of meter data,

(c) reconciliation with updated estimates of meter data,

the ISO will recover the cost of recalculating and reissuing the affected statement of account from the customer taking service from the relevant metering equipment. The customer must pay to the ISO $1,000 for each recalculated and reissued statement of account.
Request for Billing Data

6 Data required to verify any billing information provided by the ISO may be made available to customers during regular business hours and the customer will be responsible to pay for all of the costs of retrieval and provision of the data.

Payment Terms

7 Notwithstanding any unresolved dispute between the ISO and the customer, the customer must pay the entire amount due, as shown on the statement of account, no later than the twentieth business day after the end of the billing period. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the ISO.

Interest and Other Charges

8(1) In the event of non-payment under the terms of subsection 7 above, interest and late payment penalties will be charged to defaulting customers.
   (a) Where non-payment exists, interest charges will be calculated on the day following the applicable transmission settlement date. The interest will be calculated at the Toronto Dominion Canadian prime rate plus 6%. Interest will be calculated from the due date to the date on which bank value is received.
   (b) In addition to the interest charge, a penalty charge will be assessed based on two days’ interest on the outstanding amount owing and calculated at the Toronto Dominion Canadian prime rate plus 6%.

(2) The ISO will also assess the defaulting customer for all administrative and collection costs relating to the recovery by the ISO of amounts owed. The ISO, at its sole discretion, may suspend system access service and realize upon any security provided by the defaulting customer if the customer is not in compliance with subsection 7 above in full or partial satisfaction (as the case may be) of all amounts owing to the ISO. System access service to the customer will not be re-instated until the customer has paid all amounts owing to the ISO in full and has restored or secured its credit facility in a manner satisfactory to the ISO, at the ISO’s sole discretion.

Revision History

2009-11-02 Revised for 2010 tariff application.
Draft released at stakeholder consultation session.
SECTION 14
PEAK METERED DEMAND WAIVER

Causes Eligible for Peak Metered Demand Waivers

1(1) The ISO may, in its sole discretion, waive metered demand for a customer for the purposes of calculating the billing capacity when the metered demand was caused by one of the following:
   (a) commissioning;
   (b) activities required to repair and maintain transmission facilities;
   (c) an event of force majeure;
   (d) compliance with a dispatch from the ISO during an emergency; or
   (e) load restoration activities following an outage of transmission facilities or distribution facilities or caused by an emergency on the transmission system.

(2) In addition, the ISO may, in its sole discretion, waive metered demand for a distribution facility owner for pre-scheduled activities required to maintain distribution facilities.

Requests for Peak Metered Demand Waivers

2 A customer may request a peak metered demand waiver through submission of the ISO’s Peak Metered Demand Waiver Request form, available on the AESO website or by request from the ISO. The Peak Metered Demand Waiver Request form must be submitted by the customer to the ISO no later than three (3) business days after the end of the billing period for which the waiver is being requested.

Revision History

2009-10-29 Revised for consistency with revised terms and conditions.
Draft released at stakeholder consultation session.
LIMITATION OF LIABILITY

Limitation of Liability
Notwithstanding anything to the contrary contained in these terms and conditions, no action lies against an ISO person, and an ISO person is not liable for an ISO tariff act, which means any act or omission carried out or purportedly carried out in performing its obligations under the ISO tariff, unless such ISO tariff act constitutes willful misconduct, negligence, breach of contract or, if the ISO tariff act is carried out by an ISO person who is an individual, if such act is not carried out in good faith. If an ISO person is liable to another person for an ISO tariff act, then the ISO person is liable for only direct loss or damage suffered or incurred by that other person.

Revision History
2009-10-20 Revised for consistency with revised terms and conditions.
Draft released at stakeholder consultation session.
SECTION 16
CONFIDENTIAL INFORMATION

Confidential Information

1(1) Both the ISO and customers will treat information as confidential in accordance with the provisions of section 103.1 of the ISO rules regarding confidential information. Confidential information will be disclosed only in accordance with the provisions of that ISO rule.

(2) When exchanging information related to the ISO tariff, a customer shall be considered a market participant for the purpose of the confidential information provisions established under section 103.1 of the ISO rules.

Revision History

2009-10-23 Revised to refer to provisions of ISO rules.
Draft released at stakeholder consultation session.
SECTION 17
DISPUTE RESOLUTION

Dispute Resolution Process

1(1) A dispute between a customer and the ISO related to the ISO tariff will be addressed in accordance with the provisions of section 103.2 of the ISO rules regarding dispute resolution.

(2) When addressing a dispute related to the ISO tariff, a customer shall be considered a market participant for the purpose of the dispute resolution provisions established under section 103.2 of the ISO rules.

Continued Obligation

2 Pending resolution of any dispute, the ISO and the customer will continue to perform their respective obligations under the ISO tariff.

Revision History

2009-10-22 Revised to refer to provisions of ISO rules.
Draft released at stakeholder consultation session.
SECTION 18
MISCELLANEOUS

Assignment

1 A customer may assign its system access service agreement or any rights thereunder to another customer who is qualified for the system access service available under such agreement, but only with the consent of the ISO, such consent not to be unreasonably withheld. In the event a Rate DTS or Rate STS agreement has been assigned, all rights and obligations associated with the service, including any and all retrospective adjustments due to deferral account reconciliation or any other adjustments, will be applied to the account of the assignee.

Compliance With ISO Directives

2 Customers must comply with dispatches and directives of the ISO which are required for performance of customers’ obligations hereunder in real-time, including, without limitation, those related to transmission connection requirements and provision of ancillary services.

Notifications

3(1) All notices given or served upon the ISO in accordance with this ISO tariff must be in writing and marked “Important” and given by personal service, email, telefax, or registered letter addressed to:

AESO
Attention: Manager, Customer Connections
2500, 330 – 5th Avenue SW
Calgary, Alberta  T2P 0L4
Fax (403) 539-2795

(2) All notices given or served upon the customer in accordance with this ISO tariff must be in writing served by personal service, registered letter, or telefax and sent to the address or addresses shown for such customer in the relevant system access service agreement.

Revision History

2009-11-02 Revised for updated tariff.
Working draft, not released.
Update on Customer Connection Model and 2010 Tariff Application

Stakeholder Information Session
Tuesday, November 3, 2009
Bow Valley Room, Westin Hotel, Calgary

The AESO invites all interested stakeholders to attend a two-part information session providing an update on the new Customer Connection Model and the 2010 Tariff Application. The session will be held on **Tuesday, November 3, 2009** in **Calgary** in the **Bow Valley Room, Westin Hotel, 320 – 4th Avenue SW, Calgary, Alberta**.

The agenda for the session is as follows:

9:30 – 11:30 a.m. **Customer Connection Model Update**
- Connection process redesign overview & status
- Highlights of Connection Model Paper (to be issued prior to the session)
- Remaining steps and schedule

1:00 – 4:30 p.m. **2010 Tariff Application**
- Point of delivery cost function and investment level update
- TFO operating and maintenance cost causation study
- 2010 rate proposals
- System access service request terms and conditions
- Contribution policy terms and conditions
- Tariff changes related to transition of authoritative documents
- Other terms and conditions changes

Snacks and beverages will be provided but lunch will **not** be served at this session. Stakeholders may attend either or both parts, as there will be little overlap of information between the two parts.

Please RSVP to karissa.pilkington@aeso.ca or 403-539-2791 by Friday, October 30, 2009.

Sincerely,

Jana Mosley, Program Director, Customer Interconnections

John Martin, Director, Tariff Applications
September 16, 2009

Participants in AESO 2010 Tariff Consultation
Members of AESO 2010 Tariff Consultation Working Groups
AESO Stakeholders

Dear AESO Stakeholder:

Re: AESO 2010 Tariff Application Filing Delayed to November 2009

The AESO has reviewed the work remaining to satisfactorily prepare its 2010 tariff application and has concluded the filing of the application should be delayed by two months, to the end of November 2009.

Throughout the consultation on the 2010 tariff, the AESO had planned to file the application in the third quarter of 2009. Earlier this summer, the filing date had been set as the end of September 2009.

However, the development of the tariff application, including examination of issues in several working groups, has expanded beyond those matters originally expected to be addressed in the application. In particular, the POD cost function update, operations and maintenance charge study, DTS operating reserve charge restructuring, and setting of maximum investment levels have all entailed changes beyond those expected when tariff consultation began.

The extension would also allow revisions to the current interconnection process to be more fully developed and reflected in the tariff. As well, additional export and import rates require further investigation before inclusion in the tariff application.

Finally, the AESO considers that time for further consultation would allow finalization of some outstanding matters being discussed in the tariff working groups. The extension would also allow final consultation with stakeholders in general on the changes being proposed in the tariff applications.

After considering all these factors, the AESO has decided to delay the filing its 2010 tariff application to the end of November 2009. The delay will allow the application to be more thorough and comprehensive, will allow additional consultation, and will accordingly aid a more efficient regulatory review.

All information related to the 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on the delay in the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
Lee Ann Kerr, Manager, Tariff Applications, AESO
Raj Sharma, Senior Tariff Analyst, AESO
2010 POD Cost Function and Investment Level Update
Draft Recommendations

AESO 2010 Tariff Consultation

September 16, 2009
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1. Introduction
Following extensive discussion, Alberta Utilities Commission (AUC) Order U2008-217 approved a number of changes to the Alberta Electric System Operator (AESO) Customer Contribution Policy and Demand Transmission Service (DTS) Point of Delivery (POD) charge rate design. Both the investment levels in the Customer Contribution Policy and the POD charge were based on a POD Cost Function.

For its 2010 General Tariff Application (GTA) the AESO reviewed and updated the POD Cost Function and the resulting investment levels. All documents relating to consultation for the 2010 GTA, including the POD Cost Update, can be accessed on the AESO’s website by following the path: Tariff ▶ Current Consultations ▶ 2010 Tariff.

2. Scope
The AESO’s current POD Cost Function is based on 48 projects from the years 1987-2006. Final cost figures for most of those projects are now available. New projects have also been initiated since 2006 providing additional data for the 2010 POD Cost Function. All data, formulas, and figures discussed in this report are provided in an accompanying Excel workbook.

In reviewing the POD Cost Function, the AESO performed the following activities.

2.1 Additional data points
The AESO collected data for interconnections since the last Customer Contribution Study (filed as Appendix F to the AESO 2007 GTA on November 3, 2006). An interconnection project is included in the update if its cost estimate is accurate to within +20%/-10% or better.

Deconstructed project information aligns with the definition of POD as utilized in the AESO’s rate design. Project cost was escalated to 2010 dollars, appropriate to the forecast year of the tariff application.

The AESO also included projects that are expected to be constructed in the near future or are complete and await final reconciled cost information. To date, 17 projects were added and one project was removed as it was cancelled, for a total of 64 greenfield projects in the POD Cost Function data set.

2.2 Project cost inflation
Recent data indicates that project cost is increasing and increasing at a rate higher than other general cost inflation indicators such as the Consumer Price Index (CPI). The AESO sorted project cost information into various categories and applied relevant publicly available cost indices to come up with a composite price index that was used to escalate the project cost instead of Alberta CPI (which was the inflation index used in the last Customer Contribution Study).
2.3 Raw greenfield interconnection project cost function
The AESO collected data as outlined above and analyzed it in order to determine the raw greenfield interconnection project cost function. The objective was to determine a cost function that represents the average cost per megawatt (MW) of capacity of greenfield projects.

2.4 Cost of upgrade projects
The AESO compared the cost of upgrade projects to the cost of greenfield projects to see if a cost function based on greenfield projects will reasonably represent the cost of most upgrade projects. Information from 64 upgrade projects was used for this comparison.

3. Methodology Overview

3.1 Availability of Data
This analysis excluded dual use projects (both DTS and Supply Transmission Service, STS), projects for generators (STS) only, and projects partially owned by the Customer. In other words this analysis included load (DTS) only projects with no customer ownership. Other types of projects were excluded for the following reasons:
- Dual use facilities are typically built to accommodate a larger generator capacity.
- STS interconnections are not charged POD costs on a monthly basis and do not receive investment.
- The AESO does not have the cost data for customer owned facilities.

The preliminary analysis component of the update utilized historical data to determine individual cost components of the project costs. This information primarily comes from the final cost data submitted by the Transmission Facility Owners (TFOs). Where final reconciled costs or their allocations were unavailable, individual cost components were determined using the estimated costs per Proposal to Provide Service (PPS) documents. Data was drawn from AESO-maintained Customer Access Services Project Information Resource (CASPIR) and Transmission Administration System Model (TASMo) databases. In addition, project information was extracted from internal Customer Contribution determinations and other project information documentation. Where reliable cost information is not available, the project was excluded from the update.

3.2 Project and Category Classification
The AESO identifies each interconnection proposal as a “Project” and assigns project identifications on a numerical basis. All project information is maintained both electronically and in hard copy, in numerically ordered project files. Project files are filed by their assigned number.

The classification of system and customer-related costs is as outlined in Article 9 of the AESO’s Terms and Conditions. When project costs are determined, the
AESO allocates these costs to the system or the customer, based on the nature of the project. For load customers, customer-related costs are the costs associated with the construction project, entailing radial transmission extensions and enhancements at adjacent substations. These costs can normally include the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer’s interconnection.

System-related costs are those project costs associated with looped transmission facilities, radial transmission lines that will become looped within five years, or in any circumstance where the AESO deems that for economics or system planning purposes a facility larger than that required to serve the customer is necessary. In those cases, the AESO classifies these portions of the project as system-related costs.

Customer-related costs are those costs that the customer is responsible for, and include standard facility costs and those costs that are deemed in excess of standard facility costs.

As defined in its 2007 tariff, AESO standard facilities are the least-cost interconnection facilities which meet good transmission practice, including reliability, protection and operating criteria and standards. These generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection. Standard facilities for any interconnection proposal meet the forecasted load requirements for that interconnection. Standard facility costs are the only costs eligible for investment under the AESO’s 2007 tariff.

Costs in excess of standard facilities are those costs that exceed the cost of the AESO deemed standard facility interconnection configurations. For example, customer preferences to construct facilities that are larger or provide more capacity than is deemed necessary by the AESO are in excess of standard facility costs. The customer is responsible for paying all customer costs in excess of AESO standard facility costs, and these costs are not eligible for AESO investment.

All costs in this study exclude any prepaid operations and maintenance (O&M) charge applied under the AESO’s 2006 and 2007 tariffs.

Figure 1 illustrates the cost determination process for new load projects.
4. Data Collection

4.1 New Projects

Table 1 lists information gathered for each project. For the “year” category, the AESO notes that the year recorded is the year in which the most recent cost estimate or actuals were received or the dollar year mentioned in such most recent document. This assumption minimizes the effect of project construction spanning several years. The AESO recognizes that cost estimates change over time, but also assumes that the most recently submitted costs reflect costs incurred “to date” on a project, and likely are a better indicator of construction-in-progress dollars. At this time final costs for 42 out of 64 projects are known.

The AESO compiled 17 new projects since the last Customer Contribution Study that had Customer Contribution determinations associated with their projects and had applied for new DTS contracts.
Table 1 – Project Information

<table>
<thead>
<tr>
<th>Information Category</th>
<th>Source of Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project #</td>
<td>Internally assigned project numbers</td>
</tr>
<tr>
<td>Project Name</td>
<td>The name associated with the project</td>
</tr>
<tr>
<td>TFO</td>
<td>The Transmission Facility Owner associated with the project</td>
</tr>
<tr>
<td>Project Description</td>
<td>A brief outline of the nature of the project</td>
</tr>
<tr>
<td>Year</td>
<td>The recorded year is the year in which actual costs were reconciled, or where unavailable the year of most recent PPS submittal.</td>
</tr>
<tr>
<td>AESO Standard Facility Cost</td>
<td>The AESO Standard Facility costs as identified in most recent customer contribution determination</td>
</tr>
<tr>
<td>Total Project Cost</td>
<td>The total project cost as identified in most recent customer contribution determination</td>
</tr>
<tr>
<td>DTS Contract Capacity</td>
<td>The DTS Contract Capacity as identified in most recent customer contribution determination</td>
</tr>
<tr>
<td>Substation Cost</td>
<td>The substation related project cost broken down into materials, engineering and construction categories.</td>
</tr>
<tr>
<td>Line Cost</td>
<td>The transmission line related project cost broken down into materials, engineering and construction categories.</td>
</tr>
<tr>
<td>Indirect Cost</td>
<td>The indirect cost that are spread over the whole project.</td>
</tr>
</tbody>
</table>

Other considerations of note include use of the composite price index for escalation. The AESO proposes that composite price index be utilized for years 1987 through 2008. For years 2009 and 2010, the AESO proposes to utilize Alberta CPI as estimated by the Conference Board of Canada in its Provincial Outlook Summer 2009 Economic Forecast completed on July 16, 2009.

4.2 Inflation
During 2008, AltaLink led a stakeholder process to identify industry concerns with the AESO’s customer contribution policy and deliver recommendations for change. These recommendations are available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff, in the document titled “AltaLink Stakeholder Process – Recommendations”. One of the recommendations was to “use an inflation factor that is representative of the Alberta market place, and incorporate a mechanism to adjust the contribution formula to account for regulatory lag”. The cross-industry stakeholder working group stated that “The AESO customer contribution formula is based on actual project costs escalated at CPI. However, the CPI escalator is significantly lower than actual transmission cost escalation rates in Alberta. The net result is increased contributions for most interconnections. Regulatory lag is further complicating this problem, which can result in a single contribution formula being

---

in place for 2-3 years. In addition, the cycle time to build a transmission interconnection is reaching lengths of 2-4 years”. In support of this statement the group provided an appendix determining the transmission cost escalation rate to be 9% for 2006-2007 as compared to a CPI escalator of 5%. The group recommended that “The AESO include an annual automatic escalator within the contribution policy, and that this should be tied to a published index” and “The AESO should also adopt an inflation factor which is reflective of transmission costs in Alberta”.

The AESO agrees with the concept of escalating the maximum local investment using publicly-available indices both for the investment levels included in a tariff application and annually between full tariff applications. The AESO examined the project cost data to establish appropriate cost categories and determine corresponding public indices. The AESO divided the project cost between substation related material, transmission line related material, engineering, and construction. The index values were used to calculate their year over year percentage increase, use of which avoids issues arising from different base years for the different indices.

The AESO considers the following indices to be representative of the different cost categories established for interconnection projects:

(a) The Canada-wide “Electric Utility Construction Price Indexes – Substations - Equipment (v735305)” index from Statistics Canada will be used for escalating substation related material cost.

(b) The Canada-wide “Electric Utility Construction Price Indexes – Transmission Line Systems - Materials (v735258)” index from Statistics Canada will be utilized for escalating transmission line related material cost.

(c) The “Consulting engineering services price indexes by market and by field of specialization - Alberta - Industrial services (v92756)” index from Statistics Canada will be used to escalate engineering related cost. Values for this index are not available for 1987-1989 and 2007-2008. For 1987-1989, the index values were approximated as the average increase in the index for the years 1990-1994. For 2007-2008, the index values were replaced with the “APEGGA - Value of Professional Services - Engineers - All Industries” values calculated using the dollar-weighted average of the escalation rates for all levels.

(d) The average of “Non-residential building construction price indexes - Calgary, Alberta - Total, industrial structures (v44176046)” and “Non-residential building construction price indexes - Edmonton, Alberta - Total, industrial structures (v44176050)” from Statistics Canada, for Calgary and Edmonton respectively, will be used to escalate construction cost.

Weighting the cost in each category by the corresponding escalator provides a composite escalator.

2 http://www.apegga.org/Members/Publications/salarysurvey.html
The average value of the composite escalator from 1987-2008 is 3.54% per year. For comparison, the average value of an escalator based on Alberta CPI is 2.99% per year. The composite escalator reaches a maximum of 9.77% in 1989 and a minimum of (5.2%) in 1991 while the escalator based on Alberta CPI reaches a maximum of 5.87% in 1991 and a minimum of 0.99% in 1993. For eight years the increase in Alberta CPI is higher than the increase in the Composite Price Index, and for 14 years the increase in Alberta CPI is lower than the increase in the Composite Price Index. This information can be found in the “escalator” tab of the supporting Excel workbook. Table 1 below shows the escalator values for 1987-2007.

<table>
<thead>
<tr>
<th>Year</th>
<th>% Year Over Year Increase in Alberta CPI</th>
<th>% Year Over Year Increase in Composite Price Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>1987</td>
<td>4.08%</td>
<td>6.74%</td>
</tr>
<tr>
<td>1988</td>
<td>2.71%</td>
<td>7.25%</td>
</tr>
<tr>
<td>1989</td>
<td>4.11%</td>
<td>9.77%</td>
</tr>
<tr>
<td>1990</td>
<td>5.78%</td>
<td>1.10%</td>
</tr>
<tr>
<td>1991</td>
<td>5.87%</td>
<td>-5.20%</td>
</tr>
<tr>
<td>1992</td>
<td>1.51%</td>
<td>0.11%</td>
</tr>
<tr>
<td>1993</td>
<td>0.99%</td>
<td>2.04%</td>
</tr>
<tr>
<td>1994</td>
<td>1.47%</td>
<td>3.90%</td>
</tr>
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<td>1995</td>
<td>2.30%</td>
<td>4.66%</td>
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<td>1996</td>
<td>2.25%</td>
<td>0.49%</td>
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<td>1997</td>
<td>1.97%</td>
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<td>1998</td>
<td>1.25%</td>
<td>3.72%</td>
</tr>
<tr>
<td>1999</td>
<td>2.47%</td>
<td>0.80%</td>
</tr>
<tr>
<td>2000</td>
<td>3.39%</td>
<td>2.86%</td>
</tr>
<tr>
<td>2001</td>
<td>2.33%</td>
<td>4.11%</td>
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<td>3.41%</td>
<td>1.92%</td>
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<td>2003</td>
<td>4.40%</td>
<td>-3.22%</td>
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<td>2004</td>
<td>1.44%</td>
<td>4.78%</td>
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<td>2005</td>
<td>2.08%</td>
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<td>2006</td>
<td>3.89%</td>
<td>7.82%</td>
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<tr>
<td>2007</td>
<td>4.99%</td>
<td>8.80%</td>
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<td>2008</td>
<td>3.14%</td>
<td>8.87%</td>
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<tr>
<td>Average</td>
<td>2.99</td>
<td>3.54%</td>
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<tr>
<td>High</td>
<td>5.87</td>
<td>9.77%</td>
</tr>
<tr>
<td>Low</td>
<td>0.99</td>
<td>-5.20%</td>
</tr>
</tbody>
</table>

5. Analysis

5.1 Construction

The analysis considered data from a total of 64 greenfield projects initiated during the 1987-2009 period. All of these projects are load-serving and have Customer Contribution determinations (except for the 18 historical projects
included as a result of Decision 2007-106, for which Customer Contribution determinations are not available). Information from the Customer Contribution determinations was extracted for each of these projects.

Figure 2 shows the relationship between the AESO Standard Facilities cost determinations and DTS contract capacity. The currently approved POD Cost Function is also provided for comparison purposes. This figure and source data can be found in the “raw-cost-function-std”, “projects” and “escalator” tabs of the Excel workbook respectively.

The trend line equation represented is \( y = 2.6021 \times x^{0.4107} \) and has correlation of \( r^2 = 0.4433 \).

The projects in the data set exhibit significant variability or “scatter”. For example, three projects between 18-20 MW capacity had project costs of $5.504, $16.499 and $30.583 million. The variability reflects different amounts of radial line required for interconnection, different substation configurations, varying geography and construction conditions, and varying levels of complexity for each interconnection.
Figure 3 shows the relationship between the total project cost and DTS contract capacity. The currently approved POD Cost Function is also provided for comparison purposes. This figure and source data can be found in the “raw-cost-function-tot”, “projects” and “escalator” tabs of the Excel workbook respectively.

The trend line equation represented is $y = 2.7617 \cdot x^{0.4089}$ and has correlation of $R^2 = 0.4182$. This is similar to the trend line equation obtained using the standard project cost. The exponent is slightly lower and the constant multiplier is slightly higher.

In the AESO’s 2010 GTA, the AESO proposes to discontinue the standard facilities definition that exists in the current tariff, and to rely on the maximum investment level to provide an appropriate cost signal to customers. This document uses total project cost to determine the POD Cost Function, reasoning for which is provided in section 5.4.
5.2 Cost Function Determination

Table 3 summarizes the cost functions based on total project cost that demonstrated the highest correlation.

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (Power)</td>
<td>$y = 2.2131 \times x^{0.3717}$</td>
<td>0.4941</td>
</tr>
</tbody>
</table>

Updated functions based on 64 projects from 1987-2009 (based on total project cost)

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed (Power)</td>
<td>$y = 2.7617 \times x^{0.4089}$</td>
<td>0.4182</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>$y = 2.7976 \times \ln(x) + 2.2365$</td>
<td>0.2793</td>
</tr>
<tr>
<td>Linear</td>
<td>$y = 0.0995 \times x + 7.393$</td>
<td>0.1601</td>
</tr>
<tr>
<td>Exponential</td>
<td>$y = 6.1516 \times e^{0.0125 \times x}$</td>
<td>0.1738</td>
</tr>
<tr>
<td>Cubic</td>
<td>$y = 7E-05 \times x^3 - 0.0127 \times x^2 + 0.6996 \times x + 2.1792$</td>
<td>0.3450</td>
</tr>
<tr>
<td>Quadratic</td>
<td>$y = -0.002 \times x^2 + 0.3049 \times x + 5.0742$</td>
<td>0.2484</td>
</tr>
</tbody>
</table>

As in the original POD Cost Function determination, the power function has the highest regression coefficient of 0.4182, which indicates moderate positive correlation between total project costs and DTS capacity. The function is very similar to the POD Cost Function approved in Decision 2007-106. The AESO believes that the power cost function provides the best representation of the total project costs, as follows:

$$\text{Average cost} = 2.7617 \times (\text{DTS Capacity})^{0.4089}$$

Although the variability of costs within the data set is significant, the projects nevertheless exhibit a clear trend of cost increasing as capacity increases. Combined with the moderate regression coefficient, the AESO concludes this equation is a reasonable average cost function for recent transmission interconnections.

5.3 Raw Cost Function

The complete derivation of the proposed POD cost function is summarized as follows:

(a) As discussed in the preceding section, the average cost function for the data based on total project cost is reproduced, and determined to be:

$$\text{Equation 1}
\begin{align*}
\text{Average cost} &= 2.7617 \times (\text{DTS Capacity})^{0.4089} \\
\end{align*}$$

(b) Fitting a series of linear functions to replicate the slopes of the power function for 0.1, 7.5 MW, 17 MW, 40 MW, and 122.8 MW points results in a cost function which is a summation of five terms. 0.1 MW is the smallest
project size while 122.8 MW is the largest project size in the 64-project data set. Breakpoints of 7.5 MW, 17 MW, and 40 MW will be used consistent with the approach approved in Decision 2007-106.

Figure 3

Linearizing the power cost function results in the following cost function:

(c) Linearizing the power cost function results in the following cost function:

**Equation 2**

\[
\text{Linearized Cost} = \$1.007 \text{ million} \\
+ (\$0.705 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\
+ (\$0.263 \text{ million/MW} \times \text{next 9.5 MW of DTS Capacity}) \\
+ (\$0.160 \text{ million/MW} \times \text{next 13 MW of DTS Capacity}) \\
+ (\$0.088 \text{ million/MW} \times \text{remaining MW of DTS Capacity})
\]

The AESO considers the cost function (Equation 2) to appropriately reflect project costs for the purposes of establishing investment levels and for rate design in the AESO’s Tariff. This information can be found in the “cost-function-tot” tab of the Excel workbook.
5.4 Investment Level Multiplier

The investment levels in the AESO’s 2007 tariff were determined by multiplying the raw cost function based on standard project costs by 1.15 and then linearizing it. It resulted in 27 data points receiving full investment, 6 data points receiving over 90% investment, 5 data points receiving at least 80% investment and hence 38 out of 48 data points, or 79% of the data points received at least 80% investment and the majority of these points receive full investment.

The final analysis component of this document proposes a similarly-developed investment cost function. However, the approach has been modified to reflect a total facilities cost basis rather than a standard facilities cost basis.

The AESO first assessed the total investment that would occur using an investment level based on a standard facilities cost function and a multiplier of 1.15, as used for the AESO’s 2007 tariff. The raw cost function based on standard facilities cost was multiplied by 1.15 and then linearized to obtain the investment function. The lower of the project standard facilities cost and the amount obtained by applying the investment function determined the available investment. The sum of the investment available for all projects was about $471 million. Of the 64 projects in the data set, 39 data points (or 61%) receive full investment, 8 data points (or 13%) receive over 90% investment, 3 data points (or 5%) receive over 80% investment and hence a total of 50 (or 78%) data points received at least 80% investment. Close match with the corresponding figures (see first paragraph of this section) resulting from AESO’s 2007 tariff suggests that using a multiplier of 1.15 remains appropriate for a standard facilities approach.

The AESO’s experience since the currently-approved “standard facilities” definition was implemented has revealed shortcomings with the “standard facilities” approach. The AESO has reexamined this approach, and provides the following comments.

(a) The standard facilities definition was implemented when the AESO’s tariff did not align particularly well with the cost of facilities used to provide service to customers. Defining standard facilities was an approach that limited investment when maximum investment levels could otherwise have significantly exceeded the actual project cost. However, under the current tariff there is better alignment between costs and investment levels. As well, the POD charge is well-aligned with investment levels. There is accordingly less need to limit investment levels through use of a standard facilities definition.

(b) The inclusion of the phrase “generally consist of a single radial transmission circuit and a single transformer” in the definition of standard facilities has resulted in a single line, single transformer configuration being considered acceptable for most projects. This was not the intent of
the standard facilities definition. The inclusion of the single line, single transformer phrase was meant to provide additional information such that a customer would not be surprised if such a configuration was proposed for an interconnection. Based on all existing interconnections, however, about half of all load substations contain more than one transformer, and about two-thirds are connected through two or more lines. It is therefore inconsistent with historical practice to consider one transformer and one line to be the standard service for an interconnection.

(c) It is generally impractical for the AESO to determine the facilities that would meet reliability, protection, and operating criteria and standards to the satisfaction of the customer. It is ultimately the customer who determines what facilities are required for satisfactory reliability and operation of the interconnection. As a result, the “standard facilities” do not limit what facilities are actually installed — only what costs are eligible for investment. The standard facilities definition’s primary impact is therefore to limit investment. The AESO considers that, with the better alignment of costs, investment level, and rates as discussed above, investment is effectively limited through the maximum investment function. There is no need for additional limitation through a “standard facilities” definition.

(d) Finally, since the majority of interconnection projects (both historically and currently) exceed the single transformer, single line “standard facilities” configuration, significant resources are expended by the AESO, the TFOs, and customers on determining, evaluating, and estimating costs for standard facilities which will never be constructed. This is inefficient, particularly in recent periods of customer load growth when resources could be more efficiently focused on project configurations that are more likely to be constructed.

For these reasons, the AESO proposes to remove the current standard facilities approach in its 2010 tariff. Instead, the interconnection for a customer will be based on those facilities which the customer considers necessary for the interconnection. Investment will be limited through a maximum investment function which would provide the same total investment based on total project costs as the standard facilities approach would provide, developed as follows.

As explained above, the standard facilities approach applied to the standard facilities cost of the 64 projects in the data set resulted in a total investment of about $471 million.

An investment function was developed using similar methodology but based on the total facilities cost for the 64 projects. The AESO calculated that a multiplier of 1.06 applied to the raw cost function based on total project cost resulted in a similar total investment for all projects of about $472 million.
Based on total facilities costs with a multiplier of 1.06, 32 data points (or 50%) receive full investment, 7 data points (or 11%) receive over 90% investment, 6 data points (or 9%) receive over 80% investment and hence a total of 45 data points (or 70%) received at least 80% investment. Fewer projects receive 80% investment based on total facilities costs compared to standard facilities costs, which is reasonable since total facilities cost more than standard facilities for several projects while total investment remains the same. The same total amount of investment is provided in both cases.

As well, the same total amount of customer contributions is required in both cases. Under the standard facilities approach, customer contributions are required both for facilities in excess of standard and for standard facilities above the maximum investment level. Under the total facilities approach, customer contributions are provided for facilities above the maximum investment level. However, under both approaches, the total amount of customer contributions is essentially the same.

5.5 Reasonability

The recommended cost function was developed using data for load-only projects. Where a project provided interconnection of both load and generation or of multiple loads, the cost function was adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. The AESO therefore proposes that the recommended cost function incorporate the substation fraction (“SF”) into each tier as follows:

Equation 3

\[
\text{DTS POD Cost} = $1.007 \text{ million} \times \text{SF} \\
+ \frac{0.705 \text{ million/MW} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity}}{\text{MW of DTS Capacity}} \\
+ \frac{0.263 \text{ million/MW} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity}}{\text{MW of DTS Capacity}} \\
+ \frac{0.160 \text{ million/MW} \times \text{next (23 multiplied by the SF) MW of DTS Capacity}}{\text{MW of DTS Capacity}} \\
+ \frac{0.088 \text{ million/MW} \times \text{remaining MW of DTS Capacity}}{\text{MW of DTS Capacity}}
\]

The AESO tested the reasonableness of these results by comparing them with the current DTS POD costs and the close match suggests that equation 3 above is a reasonable representation of average POD costs. A consistent and proportionate increase in all five terms of the cost function indicates that all costs have risen since the last study.

The AESO also considered whether the total facilities cost function would impact the DTS POD charge, compared to the standard facilities cost function. The POD charge depends primarily on the “shape” of the cost function rather than its level, as the POD charge revenue requirement is allocated proportionately over the cost function tiers. The total facilities cost function results in a POD charge that is essentially the same as that resulting from a standard facilities cost function, with POD charge components varying by no more than ±1.2% between the two approaches. The AESO also notes that the POD charge resulting from the proposed total facilities cost function also varies only slightly from the POD...
charge that would result from the POD cost function approved during the AESO’s 2007 GTA. The AESO therefore concludes that the proposed total facilities cost function is a reasonable basis for determining the DTS POD charge.

5.6 Upgrades
The AESO investigated whether projects that involve upgrades to existing PODs have a different relation between upgrade cost and incremental DTS capacity. Unit cost of these upgrade projects was plotted against the average of the DTS capacity before and after the upgrade. Investment tier levels based on total project cost with a multiplier of 1.06 are plotted to compare with. This information can be found in the "upgrade-projects" tab of the Excel workbook.

![Figure 4](image)

The AESO considers that the proposed cost function, though based on the data from greenfield projects, sufficiently reflects the cost of most upgrade projects.

5.7 Primary Service Credit
Currently the Primary Service Credit (PSC) determination is based on the division of cost of interconnection between substation related costs and line related costs. The AESO included interconnection project cost information that has become available since the last PSC determination to update the
The AESO notes that this represents a significant increase to the ratio. The data for the increased ratio has been thoroughly examined and supports the higher ratio. As well, a review of the limited data on costs examined in the POD cost function in the Wires-Only Cost Causation Study filed with the AESO’s 2006 GTA supports the higher ratio of substation costs.

The AESO proposes to continue the approach for determining the Primary Service Credit which was approved in its 2007 GTA. That is, credits for the fixed ($/month) and first three demand ($/MW) tiers will be 78% of the corresponding component of the POD charge. The credit for the final demand ($/MW) tier will be 100% of the corresponding component of the POD charge.

Similar, the maximum investment available to a customer receiving the Primary Service Credit will be reduced by 78% for the fixed and first three demand tiers. No investment will be available for the final demand tier.

6. Conclusion
The AESO believes this update meets the requirements of Decision 2007-106 and provides an updated POD Cost Function.

The AESO notes that the interconnection project construction costs showed moderate correlations with DTS contract capacities ($^{2}=0.4182$).

The proposed cost function (equation 3) is based on the establishment of a fixed component of the cost function. The fixed component represents costs a customer cannot avoid regardless of what decisions the customer makes.

Using a multiplier of 1.06 as discussed in section 5.4 results in the DTS POD Cost given by equation 4 below:

**Equation 4**

\[
\text{DTS POD Cost} = 1.067 \text{ million} \times \text{SF} \\
+ 0.747 \text{ million/MW} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity} \\
+ 0.279 \text{ million/MW} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity} \\
+ 0.170 \text{ million/MW} \times \text{next (23 multiplied by the SF) MW of DTS Capacity} \\
+ 0.093 \text{ million/MW} \times \text{remaining MW of DTS Capacity}
\]
Equation 4 above assumes contract terms of 20 years. Therefore, the per year investment level is:

**Equation 5**

\[
\text{Investment Level} = \$53,352/\text{year of contract term} \times \text{SF} + \\
\quad + \$37,370/\text{MW}/\text{year of contract term} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity} \\
\quad + \$13,956/\text{MW}/\text{year of contract term} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity} \\
\quad + \$8,491/\text{MW}/\text{year of contract term} \times \text{next (23 multiplied by the SF) MW of DTS Capacity} \\
\quad + \$4,649/\text{MW}/\text{year of contract term} \times \text{remaining MW of DTS Capacity}
\]
POD Cost Function and Investment Level Update Working Group  
POD Charge as Approved in 2007 GTA Refiling (IR Schedule Comm.AESO-001 (h)-B-5.6 Dated March 26, 2008)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Reference</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
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<tr>
<td>1</td>
<td>Power Function</td>
<td>2007-106 p50</td>
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<td>2</td>
<td>Data Points (MW)</td>
<td>2007-106 p37</td>
<td>0.1 MW</td>
<td>7.5 MW</td>
<td>17 MW</td>
<td>40 MW</td>
<td>122.8 MW</td>
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<td>Calculated Values ($ 000 000)</td>
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<td>POD Cost Classification</td>
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<td>5</td>
<td>Intercept and Slopes ($ 000 000)</td>
<td>Lines 2 and 3</td>
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<td>Billing Determinants (cust-months, MW-months)</td>
<td>Table 4-10</td>
<td>4,854.4</td>
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<td>Total Cost Function Costs ($ 000 000)</td>
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<td>$ 16,450.4</td>
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<td>Cost Classification (%)</td>
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<td>54.6%</td>
<td>15.5%</td>
<td>10.2%</td>
<td>5.3%</td>
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<td>9</td>
<td>Costs Functionalized as Point of Delivery</td>
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<td>10</td>
<td>Wires Costs</td>
<td>Table 4-6</td>
<td>$ 27.0</td>
<td>$ 102.5</td>
<td>$ 29.1</td>
<td>$ 19.1</td>
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<td>Non-Wires Costs</td>
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<td>Line 10 + Line 11</td>
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<td>$ /MW</td>
<td>$ /MW</td>
<td>$ /MW</td>
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Note:  
1. The “Customer” billing determinant at Line 6 Col A is the sum over all DTS customers of the Substation Fraction for each DTS customer  
2. The “Demand” billing determinants at Line 6 Cols B-E are the sums over all DTS customers of billing capacity within the bounds indicated as (amounts × Substation Fraction) for each DTS customer
Dear Working Group Member:

Re: Final POD Cost Data Set for 2010 Tariff Application

Enclosed is the final point of delivery (POD) cost data set to be used for the AESO’s 2010 tariff application. The data set updates the version posted on the AESO’s website on May 28, 2009, to reflect conclusions reached in discussions with the POD Cost Function and Investment Level Update Working Group as well as with other working groups.

The data set is presented in the Excel Workbook titled “2009-09-09 AESO 2010 Tariff Consultation – POD Cost Update Data.xls”. The AESO offers the following comments on the information provided in the nine worksheets in the workbook.

The first worksheet, “projects”, includes description, cost, and capacity information for the 64 greenfield projects and 67 upgrade projects in the data set. All cost data on this first worksheet is in original cost dollars.

The second worksheet, “escalator”, provides the composite price index used in subsequent worksheets to escalate the original costs to 2010, the base year for the AESO’s tariff application. The composite price index is a weighted average of Statistics Canada indices from 2987 to 2008, and a forecast of the Alberta Consumer Price Index for 2009 and 2010.

The third worksheet, “cost-function-std”, first escalates the greenfield standard facilities project costs to 2010 and then, in the fourth worksheet, “raw-cost-function-Std”, determines the average power curve function that is a best fit through the escalated standard facilities cost data points. The “cost-function-std” worksheet also provides the straight line segment average cost function based on that power curve, and a similar function after application of a 1.15 multiplier, using the methodology approved in the AESO’s 2007 GTA proceeding.

In the AESO’s 2010 GTA, the AESO proposes to discontinue the standard facilities definition that exists in the current tariff, and to rely on the maximum investment level to provide an appropriate cost signal to customers. As a result, the fifth worksheet, “cost-function-tot” escalates the greenfield total project costs to 2010 and then, in the sixth worksheet, “raw-cost-function-Tot”, determines the average power curve function that is a best fit through the escalated total cost data points. The “cost-function-tot” worksheet also provides the straight line segment average cost function based on that power curve, and a similar function after
application of a 1.06 multiplier. The 1.06 multiplier applied to the average total cost function results in approximately the same AESO investment as the 1.15 multiplier applied to the average standard facilities cost function, based on the 64 projects included in the data set.

The seventh worksheet, “compare-std-tot”, provides a comparison of the actual investment in each of 64 projects under the two approaches — the existing approach based on standard facilities cost and a multiplier of 1.15, and the proposed approach based on total cost and a multiplier of 1.06.

The eighth worksheet, “upgrade-projects”, graphs:
- the unit investment, in $/MW, available under the proposed approach and
- the average unit cost, in $/MW, for the upgrade projects included in the data set.

In general, the AESO considers that the unit investment reasonably reflects the unit costs of the upgrade projects.

The ninth and final worksheet, “psc”, provides the average percentage of POD costs attributable to substation and line on which the primary service credit and related investment level is based. Based on the 46 projects for which detailed costs are available, the substation costs represent 78% of total project costs, compared to the 55% used for the current tariff. The primary service credit will therefore be proposed to increase in the 2010 tariff, and the maximum investment available for such projects will decrease.

Note that although this workbook is considered final in form and structure, it may be further updated with more recent data if such data becomes available prior to the filing of the AESO’s 2010 tariff application.

The workbook and all other printed information related to the POD Cost Function and Investment Level Update Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

The AESO will be contacting members of the POD Cost Function and Investment Level Update Working Group to schedule one final meeting to discuss these results in the next few days. In the meantime, if you have any comments or questions on the final POD cost data set or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosure

cc: Raj Sharma, Senior Tariff Analyst, AESO
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<tr>
<th>Project</th>
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**Brintnell Substation: ATCO**
- 138/25 kV substation with 1 - 30/40/5

**Lloydminster Substation: ATCO**
- New substation, transformer and breakers

**Foster Creek Substation: ATCO**
- New substation with two customers

**Dray Lake Substation: ATCO**
- 2 new sub and transmission lines

**Lakeview Substation: UNC**
- New sub and associated transmission lines

**Flint Lake Substation: UNC**
- New sub and associated transmission lines

**New 138/25 kV substation to support load growth**

**Introl Substation: ENMAX**
- New 138/25 kV substation to accommodate load growth

**Taylors Gas Substation: Fortis**
- New 138/25 kV Substation with Transformer

**ENMAX Substation: Fortis**
- 138/25 kV Substation Construction

**Fortis - Viscount (St. Albert) AML**
- New substation (138kV/25kV) to accommodate load growth

**Fortis Christina Lake AML**
- New load of 6MW at Christina Lake Substation

**Terasen - Peace Butte Station AML**
- New load of 6MW at Peace Butte Substation

**Ametek (108S) - new substation AML**
- New Point of Interconnection for the Heartland

**Bassano Substation AML**
- New Bassano 138/25kV substation to accommodate load growth

**Petro-Canada Edmonton Refinery AML**
- New substation facilities to supply 15MVA

**Twin Butte Substation AML**
- New 138/25kV substation with 1 - 30/40/5

**Twin Butte Substation AML**
- New 138/25kV substation with 1 - 30/40/5

**EnCana Countess AML**
- New 138/25kV substation to accommodate load growth

**EnCana - Redwater AML**
- New 138/25kV substation to accommodate load growth

**EnCana - Redwater AML**
- New 138/25kV substation to accommodate load growth

**Air Products Edmonton Refinery AML**
- New substation facilities to supply 15MVA

**TransCanada Edson Gas AML**
- New Marlboro 348S 138/4.16kV Substation

**Fortis - Bretona Substation AML**
- New Substation (138kV/25kV) to accommodate load growth

**ENMAX No. 5 Substation AML**
- New 138/25kV distribution point of delivery to customers

**Fortis Christina Lake AML**
- New 138/25kV (KMK) load

**New Whitfield 1335 138/25 kV AML**
- New 138/25kV substation to support load growth

**Enmax 47 AML**
- New and New 138/25 kV substation with 1 - 30/40/5

**Amata (108S) - new substation AML**
- New point of interconnection for the Heartland
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<th>Project Name</th>
<th>TFO</th>
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<th>AESO Standard Cost</th>
<th>DTS (MM)</th>
<th>Substation Related Cost</th>
<th>Line Related Cost</th>
<th>Engineering Related Cost</th>
<th>Construction Related Cost</th>
<th>Excavated ASEO Standard Cost</th>
<th>Using Composite Index (5 Million)</th>
<th>DTS Increase (MM)</th>
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<td>Fortis - Suffield 895S AML PH 1- Regulator upgrade, feeder addition; 2003</td>
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<td>$8,974,000</td>
<td>$7,938,000</td>
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Note: Costs are based on +20%/-10% estimates or better, available as of whatever date the data was most recently updated.
| Project ID | Project Description | Phase | Contract Value | MW | DTS (MW) | Up/Down | Change
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<tr>
<td>733</td>
<td>Fortis - Blackmud AML Upgrade to 155S including one 138/25kV transformer</td>
<td>2008</td>
<td>$5,738,000</td>
<td>41.40</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>748</td>
<td>ATCO - Three Hills ATCO 25kV Breaker Addition</td>
<td>2008</td>
<td>$415,000</td>
<td>26.54</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>755</td>
<td>ATCO - Ethel Lake ATCO Capacity Upgrade - New 144/25kV transformer</td>
<td>2008</td>
<td>$2,477,670</td>
<td>16.00</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>778</td>
<td>ATCO - Mahihkan ATCO 25kV Breaker Addition</td>
<td>2008</td>
<td>$354,000</td>
<td>2.00</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>804</td>
<td>Fortis - Northwest Cardiff AML Transformer addition and 2.5 25 kV breakers</td>
<td>2008</td>
<td>$2,602,000</td>
<td>24.30</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>808</td>
<td>ATCO - Hayter AML One 25 kV breaker Addition</td>
<td>2008</td>
<td>$503,100</td>
<td>25.20</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>874</td>
<td>Fortis - Hick Lake AML Replacement of 7.5/4 MVA transformers</td>
<td>2008</td>
<td>$0</td>
<td>230.00</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
<tr>
<td>902</td>
<td>Fortis - Hardisty AML Addition of a 25 kV breaker</td>
<td>2009</td>
<td>$540,000</td>
<td>32.70</td>
<td>0.00</td>
<td>8.40</td>
<td>15.50</td>
</tr>
</tbody>
</table>

Note: Following Project was excluded because of its extremely small DTS MW increase

178 CP Rail Ak-Suluk 25kV service upgrade to existing 69kV

182 Fortis - Hardisty AML Addition of a 25 kV breaker | 2009 | $540,000 | 32.70 | 0.00 | 8.40 | 15.50 |
June 11, 2009

POD Cost Function and Investment Level Update Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for POD Cost Function and Investment Level Update Working Group

The second meeting of the POD Cost Function and Investment Level Update Working Group for the AESO’s 2010 tariff application is scheduled as follows:

| Time: | 9:00 to 11:00 AM |
| Date: | Friday, June 12, 2009 |
| Location: | Meeting Room 2539, AESO Office, 330 – 5th Avenue SW, Calgary |
| Refreshments: | Coffee, juice, and pastries |

This working group includes the following members:

- AltaLink: Dean Fischbach
- DUC: Dale Hildebrand
- ENMAX: Penny Haldane
- IPCAA: Sheldon Fulton
- TransCanada: Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. IPCAA has already advised that they are unable to participate in this first meeting.

The agenda for the meeting is proposed to include the following items:

1. **Review agenda**
   - 9:00 AM

2. **Review draft meeting notes for May 19, 2009**
   - 9:05 AM
   - Please see enclosed draft meeting notes

3. **Inflation index used to escalate historical costs to 2010**
   - 9:10 AM
   - Are there concerns with using different indices for historical and forecast costs?
   - Are there additional concerns with the composite historical index?
   - Are there other ways to address the concerns around volatility and the need for a reliable forecast for the index?
4 **Applicability to upgrade projects**
- Please review section 5.5 of the discussion paper
- Are there other considerations for ensuring the POD cost function reasonably reflects costs for upgrade as well as greenfield projects?

5 **Development of maximum investment level**
- How can the POD cost function be translated into a maximum investment level?
- What approach should be used in the absence of an “80/20 rule”?
- How can the contribution policy design considerations mentioned by the AUC in Decision 2007-106 (page 94) be addressed?
  - Sending of economic signals
  - Removal of incentives to pursue facilities beyond those required
  - Avoidance of undue upward pressure on rates
  - Anticipated costs of an interconnection
  - Changes to service characteristics and standards of functionality

6 **Updates in future rate applications**
- How should investment level be updated as part of a rates update application (between general tariff applications)?

7 **Follow-up required for next meeting**
- Summarize what tasks need to be completed before next meeting and who will complete them

8 **Dates and times for next meeting(s)**

9 **Adjourn**

This agenda and all other printed information related to the POD Cost Function and Investment Level Update Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
The following notes summarize items on which participants had discussion of substance. If an agenda item was simply reviewed and acknowledged, it is not included in these notes.

1 Participants
   - AltaLink: Dean Fischbach (representing AltaLink TFO)
   - DUC: Dale Hildebrand (representing dual use (DTS and STS) customers, specifically Air Liquide, CNRL, Imperial Oil, Petro-Canada, Shell, Suncor, and Total)
   - ENMAX: Penny Haldane (representing ENMAX Power TFO and DFO)
   - TransCanada: Chris Best (representing TransCanada Energy and TransCanada Keystone Pipeline, primarily load)
   - UCA: Ed de Palezieux (representing residential, farm, and commercial loads)
   - AESO: John Martin and Raj Sharma

2 Action Items
   (a) AESO: Provide POD charge calculations used on POD cost function escalated with Alberta CPI and with the composite index (item 6(a)).
   (b) AltaLink: Provide information on cost index used by TFOs (item 6(b)).

3 Next meeting
   (a) 9:00-11:00 AM on Friday, June 12, 2009.

4 New “blue sky” approaches to determining investment level
   (a) Participants agreed that new approaches could be looked at after an “update” approach had been discussed in the working group. DUC and UCA may bring forward some ideas at a future meeting.

5 Inviting comments on discussion paper
   (a) Participants agreed that inviting stakeholder comments on the discussion paper should wait until the working group had more fully reviewed and discussed the paper.

6 Selection and application of cost index for the POD cost update
   (a) The AESO agreed to provide the POD charge that would result from POD costs updates using the Alberta CPI and using the composite price index, based on costs and billing determinants used in the AESO’s 2009 rates update application.
   (b) AltaLink will provide information on the cost index used by TFOs.
   (c) Participants suggested the same index did not necessarily need to be used for both historical and forecast years. The composite price index could be used for historical years, while Alberta CPI could be used for forecast years.
   (d) Participants were interested in a graphical comparison of the composite price index and Alberta CPI. The data for both was included in the Excel workbook provided with the discussion paper, so participants can view the data directly.
7 Contract capacity and metered demand
(a) Participants suggested there is a disconnect between the capacity contracted for by a customer and the actual metered demand for the customer. Customers in unconstrained areas may under-contract to “hoard” capacity to maximize investment when a substation needs to be expanded. Customers in constrained areas may over-contract to ensure they have capacity available to them when their actual load grows. Such mismatches create challenges for system planners and operators.
(b) The AESO is proposing to base investment at an expanding substation on the contract increase since the last time the customer received investment, which may address the “capacity hoarding” concern.
(c) Participants suggested it might be worthwhile to compare metered demand and contract capacity for interconnection projects. Such information may involve customer-specific data which is usually treated as confidential.

8 Enclosures
(a) Excel workbook with POD charge calculations based on Alberta CPI and based on composite index.
(b) Information on cost index used in AltaLink’s 2009-2010 General Tariff Application:
   – section 6.1 on capital costs overview from application, dated September 16, 2008, and
## POD Cost Function and Investment Level Update Working Group

**POD Charge as Approved in 2007 GTA Refiling (IR Schedule Comm.AEOS-001 (h)-B-5.6 Dated March 26, 2008)**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Reference</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Power Function</td>
<td>2007-106 p50</td>
<td>Customer Demand</td>
<td>0.37</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Data Points (MW)</td>
<td>2007-106 p37</td>
<td>0.1 MW</td>
<td>7.5 MW</td>
<td>17 MW</td>
<td>40 MW</td>
<td>122.8 MW</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Calculated Values ($ 000 000)</td>
<td>Lines 1 and 2</td>
<td>$ 0.944</td>
<td>$ 4.664</td>
<td>$ 6.313</td>
<td>$ 8.665</td>
<td>$ 13.122</td>
<td></td>
</tr>
</tbody>
</table>

### POD Cost Classification

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Reference</th>
<th>Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>POD Cost Classification</td>
<td>Lines 2 and 3</td>
<td>Fixed</td>
</tr>
<tr>
<td>5</td>
<td>Intercept and Slopes ($ 000 000)</td>
<td>Lines 2 and 3</td>
<td>$ 0.894</td>
</tr>
<tr>
<td>6</td>
<td>Billing Determinants (cust-months, MW-months)</td>
<td>Table 4-10</td>
<td>$ 0.503</td>
</tr>
<tr>
<td>7</td>
<td>Total Cost Function Costs ($ 000 000)</td>
<td>Line 5 × Line 6</td>
<td>$ 4.339.8</td>
</tr>
<tr>
<td>8</td>
<td>Cost Classification (%)</td>
<td>Line 7 + Col F</td>
<td>14.4%</td>
</tr>
</tbody>
</table>

### Costs Functionalized as Point of Delivery

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Reference</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Wires Costs</td>
<td>Table 4-6</td>
<td>$ 27.0</td>
<td>$ 102.5</td>
<td>$ 29.1</td>
<td>$ 19.1</td>
<td>$ 9.9</td>
<td>$ 187.7</td>
</tr>
<tr>
<td>10</td>
<td>Non-Wires Costs</td>
<td>Table 4-6</td>
<td>1.3</td>
<td>5.1</td>
<td>1.4</td>
<td>1.0</td>
<td>0.5</td>
<td>9.3</td>
</tr>
<tr>
<td>11</td>
<td>Total POD-Functionalized Costs</td>
<td>Line 10 + Line 11</td>
<td>$ 28.4</td>
<td>$ 107.6</td>
<td>$ 30.6</td>
<td>$ 20.1</td>
<td>$ 10.4</td>
<td>$ 197.0</td>
</tr>
</tbody>
</table>

### POD Charge

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Reference</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>POD Charge</td>
<td>Line 12 ÷ Line 6</td>
<td>$ 5,849.00</td>
<td>$ 3,291.00</td>
<td>$ 1,138.00</td>
<td>$ 667.00</td>
<td>$ 353.00</td>
<td></td>
</tr>
</tbody>
</table>

**Note:**

1. The “Customer” billing determinant at Line 6 Col A is the sum over all DTS customers of the Substation Fraction for each DTS customer.
2. The “Demand” billing determinants at Line 6 Cols B-E are the sums over all DTS customers of billing capacity within the bounds indicated as (amounts × Substation Fraction) for each DTS customer.
6 CAPITAL COSTS

Section 6 of AltaLink’s Application addresses the following:

6.1 Overview
6.2 Capital Resource Additions
6.3 Direct Assigned Projects
6.4 Capital Replacements and Upgrades
6.5 Power System Risk Mitigation Projects
6.6 Information Technology Capital Costs
6.7 Facility Capital Costs
6.8 Capital Execution
6.9 Operational Performance
6.10 AltaLink Capitalization Policy

6.1 OVERVIEW

AltaLink’s forecast 2009-2010 capital expenditures are summarized below and detailed in Schedules 6.2 and 6.3.

2009 Forecast $556.0M
2010 Forecast $744.2M

AltaLink’s forecast capital expenditures include: (1) costs in respect of projects directly assigned by the AESO and projects forecast to be assigned by the AESO (collectively, “Direct Assigned Projects”); (2) capital replacements and upgrades; (3) Power System Risk Mitigation projects which is a new capital category beginning in 2009; and (4) general capital expenditures, all as detailed in Table 6.1a and described throughout Section 6. Capital expenditures are comprised of those charges that are directly attributable to the capital projects, indirect labour and overhead allocated to the capital projects, and Allowance for Funds Used During Construction (“AFUDC”).

September 16, 2008
Please see the “Forward Looking Information Advisory” on pages i-iv of this volume.
Table 6.1a - 2009-2010 Forecast Capital Expenditures ($M)

<table>
<thead>
<tr>
<th>Description</th>
<th>2009 Forecast</th>
<th>2010 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Assigned Projects</td>
<td>$433.9</td>
<td>$628.3</td>
</tr>
<tr>
<td>Capital Replacements and Upgrades</td>
<td>97.4</td>
<td>87.1</td>
</tr>
<tr>
<td>Power System Risk Mitigation</td>
<td>7.7</td>
<td>9.1</td>
</tr>
<tr>
<td>Information Technology</td>
<td>13.8</td>
<td>15.2</td>
</tr>
<tr>
<td>Buildings</td>
<td>3.2</td>
<td>4.5</td>
</tr>
<tr>
<td><strong>Total Capital Expenditures</strong></td>
<td><strong>$556.0</strong></td>
<td><strong>$744.2</strong></td>
</tr>
</tbody>
</table>

(Totals may vary due to rounding.)

AltaLink’s forecast capital expenditures reflect the tremendous transmission growth in recent and forecast years. As demonstrated in Figure 6.1a, AltaLink has executed over $516M in direct assigned projects in the five years ending in 2007 and is forecasting an additional $1,503.8M from 2008 through 2010.

Figure 6.1a - Direct Assigned Project Expenditures (Nominal $M)

This unprecedented transmission system growth directly translates into AltaLink’s increased efforts to operate and maintain its facilities and has a network effect on other aspects of AltaLink’s application. AltaLink’s 2009-2010 Power System Risk Mitigation projects and Capital Replacements and Upgrades are forecast at a level to manage transmission asset reliability, safety and environmental risks. Forecast Information
Technology and Building capital expenditures reflect AltaLink’s cost to provide the tools necessary to oversee its transmission system.

**Market Conditions**

AltaLink has been very focused on monitoring and forecasting transmission project cost escalation factors over the past few years. The volume of direct assign project execution for AltaLink has increased almost 3 fold, averaging $63M from 2003-2005 versus $150M from 2006-2008. AltaLink has included market price increases within this GTA forecast averaging 10% per year for transmission capital projects. This escalation is based on market conditions for material, construction labour, and professional service labour such as engineering, land agents, environmental, and consultation.

**Material Commodities**

World wide demand for commodities over the past several years has resulted in cost increases well above general inflation levels in every key transmission material commodity including steel, aluminum, copper, cement, and electrical wire.

![Figure 6.1b – Steel Mill Products Price Index](image-url)
Please see the “Forward Looking Information Advisory” on pages i-iv of this volume.
**Construction Labour**

Within the US, national labour costs have also increased at rates well above general inflation, a trend that has occurred since 1997. The labour cost indices below include heavy construction labour, common labour and craft labour, all of which are used in utility infrastructure construction. Of greater concern is the emerging gap between demand and supply of skill construction labour driven by the pending boom in utility construction within the US and the attrition of skilled workforce due to retirements.
Engineering, Procurement and Construction (EPC) Market Conditions

The increased worldwide demand for electric infrastructure development, particularly in China and India, has doubled the project backlog for major US EPC firms (Flour Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd.) between 2002 and 2006. The growth in construction project backlogs will place upward pressure on pricing in this market.

Transmission Cost Indices

With all three main components of transmission development increasing at rates above general inflation, it is not surprising that the overall transmission cost indices are rising much more rapidly than general inflation. The Handy-Whitman Indexes provided below illustrate these increases.
Figure 6.1h – RSMeans Historical Construction Cost Index

The above graph illustrates that during the period from 1991 to 2004, transmission costs rose at slightly above the rate of inflation. A dramatic increase has occurred between 2004-2007, rising almost 30% or nearly 4 times the annual rate of inflation over that period.

September 16, 2008

Please see the “Forward Looking Information Advisory” on pages i-iv of this volume.
AltaLink’s Experience in Alberta

AltaLink has been at the forefront of new transmission project development within Alberta over the 4 year period of 2005 – 2008 with approximately $547M in direct assign project expenditures. AltaLink provides the following Alberta centric data to assist the Commission in understanding the transmission project cost annual inflation within Alberta.

Engineering and construction labour costs are driven more from the Alberta supply/demand market since these costs are accessed primarily within Alberta. For major projects, such as the Edmonton-Calgary 500 kV project, AltaLink entered the North American market for construction services. The North American market data is relevant for major projects and as the demand for transmission construction services begins to exceed the supply within Alberta, the North American market becomes more important and indicative of future escalation pressures.

AltaLink is projecting a $1.1B direct assign capital expenditure forecast for the 2009 and 2010 test period. With this increased pressure on the demand side of the market, AltaLink anticipates an annual escalation of at least 10% for transmission project costs, a weighted average increase of 8% for professional services, 8% for material and 12% for construction.
### Table 6.1b – Service Cost Increases

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Engineering</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td>APEGGA-2004-2007 Salary Survey</td>
<td>2.8%</td>
<td>4.8%</td>
<td>6.9%</td>
<td>4.4%</td>
</tr>
<tr>
<td>PM-Engineering Average Cost increase</td>
<td></td>
<td>4.4%</td>
<td>5.4%</td>
<td>8.2%</td>
<td>7.7%</td>
</tr>
<tr>
<td>Price indices of non-residential building construction</td>
<td>Stats Canada - Construction Alberta- Industrial- Institutional- 2003-2007</td>
<td>10.55%</td>
<td>6.80%</td>
<td>17.23%</td>
<td>11.18%</td>
</tr>
<tr>
<td>Total Transmission Plant - Construction and Equipment</td>
<td>Handy Whitman - Total Transmission Plant - ALL Regions Average - Construction and Equipment</td>
<td>9.30%</td>
<td>6.72%</td>
<td>8.63%</td>
<td>8.01%</td>
</tr>
<tr>
<td>Equipment Average</td>
<td></td>
<td>9.3%</td>
<td>6.7%</td>
<td>8.6%</td>
<td>8.0%</td>
</tr>
<tr>
<td><strong>Weighted Average</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td></td>
<td>32%</td>
<td>4.4%</td>
<td>5.4%</td>
<td>8.2%</td>
</tr>
<tr>
<td>Equipment</td>
<td></td>
<td>34%</td>
<td>9.3%</td>
<td>6.7%</td>
<td>8.6%</td>
</tr>
<tr>
<td>Construction</td>
<td></td>
<td>34%</td>
<td>10.6%</td>
<td>6.8%</td>
<td>17.2%</td>
</tr>
<tr>
<td>Weighted Average</td>
<td></td>
<td>8.2%</td>
<td>6.3%</td>
<td>11.4%</td>
<td>9.0%</td>
</tr>
</tbody>
</table>

Summarized in chart form in Figure 6.1j, the overall weighted average annual increase over the past two years has been approximately 10%.
5 6.2 CAPITAL RESOURCE ADDITIONS

Altalink’s capital staffing resource requirements are a direct result of Altalink’s capital expenditure forecast for the test period. As shown in Figure 6.2, Altalink’s capital expenditure since 2005 to 2010 is forecast to increase by approximately 350% from an actual of approximately $140M in 2005 to a forecast of approximately $759.3M in 2010. This increase has had and continues to have a direct impact on Altalink’s resource levels, particularly those areas which directly work on capital projects. The departments most affected by the capital work load increase are; Projects, Information Technology, Field Operations, Asset Management and External Engagement. These departments require the greatest level of resource increases in order to deliver the capital programs, with the remaining departments showing increases to a lesser degree.
Topic: Market Conditions

Reference: Section 6.1

Preamble:

AltaLink has included market price increases within this GTA forecast averaging 10% per year for transmission capital projects. This escalation is based on market conditions for material, construction labour, and professional service labour such as engineering, land agents, environmental, and consultation.

Request:

a) Please provide updates to the market conditions forecast for 2009 and 2010 having regard to the current economic outlook. Provide an assessment of the impact of the current economic outlook for Alberta on the inflation assumptions used for forecasting capital expenditures in 2009 and 2010.

b) Provide updates to the indices in figures 6.1b to 6.1j to reflect the most recent available data.

Response:

a) Please refer to responses to IPCAA.AML-046 and UCA.AML-067 [both to be filed with the balance of IR Responses].

b) AltaLink’s Figures 6.1b to 6.1i were sourced from the Edison Foundation Rising Utility Construction Costs report, dated September 2007; updated information is not available from this source. AltaLink does not have access to the source data for the report. AltaLink has updated Figure 6.1j with 2008 data, as provided below.
## Updated Table 6.1b Service Cost Increases

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering</td>
<td>APEGGA - 2004-2008 Annual Salary Survey (Base salaries)</td>
<td>2.8%</td>
<td>4.8%</td>
<td>5.8%</td>
<td>7.4%</td>
<td>4.6%</td>
</tr>
<tr>
<td><strong>PM-Engineering</strong></td>
<td><strong>Average Cost increase</strong></td>
<td>4.5%</td>
<td>5.5%</td>
<td>7.7%</td>
<td>9.4%</td>
<td>4.6%</td>
</tr>
<tr>
<td>Price indices of non-residential building</td>
<td>Statistics Canada: Construction Alberta; - Industrial Institutional- 2003-2008. Methodology: Average of Quarterly indices for each year</td>
<td>7.4%</td>
<td>7.1%</td>
<td>12.1%</td>
<td>15.2%</td>
<td>15.40%</td>
</tr>
<tr>
<td>Total Transmission Plant - Construction and</td>
<td>Handy Whitman: Total Transmission Plant; - All Regions Average - Construction and Equipment</td>
<td>9.3%</td>
<td>6.7%</td>
<td>8.6%</td>
<td>8.0%</td>
<td>10.10%</td>
</tr>
<tr>
<td>Equipment</td>
<td><strong>Average Cost Increase</strong></td>
<td>9.3%</td>
<td>6.7%</td>
<td>8.6%</td>
<td>8.0%</td>
<td>10.1%</td>
</tr>
<tr>
<td>Engineering</td>
<td>32% from 2003 to 2007 and 38% in 2008</td>
<td>4.5%</td>
<td>5.5%</td>
<td>7.7%</td>
<td>9.4%</td>
<td>4.6%</td>
</tr>
<tr>
<td>Equipment</td>
<td>34% from 2003 to 2007 and 37% in 2008</td>
<td>9.3%</td>
<td>6.7%</td>
<td>8.6%</td>
<td>8.0%</td>
<td>10.1%</td>
</tr>
</tbody>
</table>
Construction | 34% from 2003 to 2007 and 25% in 2008 | 7.4% | 7.1% | 12.1% | 15.2% | 15.40%
---|---|---|---|---|---|---
Weighted Average | 7.1% | 6.4% | 9.5% | 10.9% | 9.3%

Updated Figure 6.1j – EPC Escalation Trend 2003-2008
May 28, 2009

POD Cost Function and Investment Level Update Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for POD Cost Function and Investment Level Update Working Group

The first meeting of the POD Cost Function and Investment Level Update Working Group for the AESO’s 2010 tariff application is scheduled as follows:

Time: 9:00 to 10:30 AM
Date: Friday, May 29, 2009
Location: Meeting Room 2539, AESO Office, 330 – 5th Avenue SW, Calgary
Refreshments: Coffee, juice, and pastries

This working group includes the following members:
- AltaLink: Dean Fischbach
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- TransCanada: Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. IPCAA has already advised that they are unable to participate in this first meeting.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   Time: 9:00 AM

2. **Review agenda**
   Time: 9:10 AM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
   Time: 9:15 AM
– Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
– A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

• Identify any concerns with or additional revisions to the terms of reference
• Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for POD cost function and investment level update 9:20 AM
• Please review the enclosed information before the meeting, if possible:
  (a) Discussion of DTS point of delivery (POD) costs and charges in Section 5.7 (pages 36-59) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (b) Discussion of customer contribution policy in Section 8.1 (pages 91-99) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
• Is there other background that participants consider particularly relevant?

5 2010 POD cost function update discussion paper 9:25 AM
• See enclosed discussion paper and supporting Excel workbook for proposed approach to updating POD cost function
• Review scope and content of discussion paper
• Discuss process to finalize discussion paper, including inviting comments from larger stakeholder audience

6 Inflation index used to escalate historical costs to 2010 9:40 AM
• Please review section 4.2 of the discussion paper
• What criteria are important in determining an appropriate inflation index?
• Are there other ways to address the concerns around volatility and the need for a reliable forecast for the index?

7 Applicability to upgrade projects 10:05 AM
• Please review section 5.5 of the discussion paper
• Are there other considerations for ensuring the POD cost function reasonably reflects costs for upgrade as well as greenfield projects?

8 Follow-up required for next meeting 10:20 AM
• Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s) 10:25 AM

10 Adjourn 10:30 AM

This agenda and all other printed information related to the POD Cost Function and Investment Level Update Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) **POD Cost Function and Investment Level Update**
- Substations included in POD cost data set
- Inflation index to escalate POD cost data to 2010
- Multiplier to determine investment level

(b) **TFO O&M Cost Causation Study**
- Respond to AUC directions on analysis of TFO O&M costs
- Determine if TFO O&M costs are energy-related
- Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) **DTS Operating Reserve Charge Design**
- Methodology to analyze and assess design of operating reserve charge
- Criteria for selection of appropriate design for operating reserve charge

(d) **Fort Nelson Rate FTS**
- Rate design principles for Fort Nelson and similar services
- Cost allocation approaches between BC and Alberta loads in the Rainbow Area
- Contractual considerations for Fort Nelson and similar services

(e) **Export and Import Rates XTS and ITS**
- Rate design principles for higher-priority export and import services
- Similarities and differences between domestic and intertie services
- Potential allocation of “deep system” costs to services over merchant interties

(f) **Deferral Account Riders B and C**
- Rate design principles for deferral account riders
- Practicality of improving allocation accuracy of deferral account riders
- Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
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 as described below:

<table>
<thead>
<tr>
<th>Table 2. Original AESO POD Cost Classification Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Component</td>
</tr>
<tr>
<td>----------------------------------------------------</td>
</tr>
<tr>
<td>Unit Cost ($000 000)</td>
</tr>
<tr>
<td>Billing Determinant</td>
</tr>
<tr>
<td>Total Costs ($000 000)</td>
</tr>
<tr>
<td>Classification</td>
</tr>
</tbody>
</table>

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>
<thead>
<tr>
<th>Table 3. Revised AESO POD Cost Classification Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Component</td>
</tr>
<tr>
<td>----------------------------------------------------</td>
</tr>
<tr>
<td>Unit Cost ($000 000)</td>
</tr>
<tr>
<td>Billing Determinant</td>
</tr>
<tr>
<td>Total Costs ($000 000)</td>
</tr>
<tr>
<td>Classification</td>
</tr>
</tbody>
</table>

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.

128 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.\(^{129}\)

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.\(^ {130}\) 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;\(^ {131}\)

\(^{129}\) AESO Argument, p. 75

\(^{130}\) The AESO, DUC, ASBG-PGA, AE, PPGA, CCA, PICA, ADC, Fortis, and IPCAA provided comments on the alternate cost function.

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 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 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:  

\[
\text{Recommended Cost} = 0.947 \text{ million} + (0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) + (0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})
\]

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. 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.

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.

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132 As discussed in section 9.1 of this Decision, the Board has adopted a convention for numbering Board directions based on the AESO’s refiling application (Application #1420890) in relation to Decision 2005-096, as approved by the Board in Decision 2005-131
133 Ex. 007, Application, Section 6, p. 22
134 AESO Argument, pp. 69-70
135 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. 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. 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. 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 and that POD costs as identified in the TCCS should be recovered by way of a customer-related charge.

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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136 PPGA Argument, p. 21
137 Decision 2001-32 direction 21 (p. 215)
138 Decision 2005-096, p. 28
139 Decision 2005-096, p. 29
“stop gap” measure to apply until further and more detailed cost causation research could be completed.\textsuperscript{141} 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.\textsuperscript{142}

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.\textsuperscript{143}

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

\begin{itemize}
  \item Decision 2005-132, p. 4
  \item Decision 2005-132, p. 4
  \item Ex. 005, Section 4.3.4 of the Application
\end{itemize}
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.\textsuperscript{144}

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.

\textsuperscript{144} 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. 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. Therefore, 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.

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...
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.\textsuperscript{148}

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.\textsuperscript{149}

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.\textsuperscript{150} 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.\textsuperscript{151} 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.\textsuperscript{152} The Board finds that DUC’s evidence on the drivers of POD costs provided compelling evidence of substantial economies of scale.

\begin{itemize}
  \item \textsuperscript{148} 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.
  \item \textsuperscript{149} Ex. 229, DUC Evidence, p. 14, citing Exhibits 23-010 and 02-019-001 from AESO 2005-2006 GTA proceeding
  \item \textsuperscript{150} AESO Argument, p. 77 of 99
  \item \textsuperscript{151} Ex. 306, CG-DUC-1(c)
  \item \textsuperscript{152} Ex. 229, DUC Evidence pp. 13-16
\end{itemize}
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.\footnote{153} 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.\footnote{154} However, the Board is not persuaded by the assertions of the AESO and PPGA that diseconomies of scale occur 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\footnote{155} 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.\footnote{156} PPGA suggested that the cost of responding to landowner opposition may increase as the POD cost size increases.\footnote{157} 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\footnote{158} 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.\footnote{159} DUC submitted, however, that the AESO’s analysis should have

\begin{footnotesize}
\begin{itemize}
  \item[153] Ex. 331, IPCAA.PPGA-1
  \item[154] Ex. 306, CG-DUC-1(c)
  \item[155] Ex. H-029
  \item[156] Tr. Vol. 6, pp. 1319-1323
  \item[157] Tr. Vol. 6, p. 1313
  \item[158] Ex. 015, Appendix F to the Application
  \item[159] DUC Argument, pp. 14-16
\end{itemize}
\end{footnotesize}
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.160

PPGA expressed a number of concerns with the POD cost function data set analyzed by the AESO.161 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.162 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.163

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.

160 DUC Argument, p. 16
161 PPGA Argument, pp. 10-11
162 PPGA Argument, p. 16
163 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.\textsuperscript{164} 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.\textsuperscript{165} However, in

\textsuperscript{164} Ex. 005, Application Section 4.5.2, p. 18
\textsuperscript{165} 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>
<thead>
<tr>
<th>Regression Analysis</th>
<th>Line Function</th>
<th>Correlation Coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linear</td>
<td>$y = 0.0985x + 5.7659$</td>
<td>$R^2 = 0.1289$</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>$y = 3.8486 \ln(x) - 3.1694$</td>
<td>$R^2 = 0.1939$</td>
</tr>
<tr>
<td>Polynomial</td>
<td>$y = -0.0017x^2 + 0.2271x + 3.2723$</td>
<td>$R^2 = 0.1843$</td>
</tr>
<tr>
<td>Power</td>
<td>$y = 1.8957 x^{0.431}$</td>
<td>$R^2 = 0.1799$</td>
</tr>
<tr>
<td>Exponential</td>
<td>$y = 5.1281 e^{0.113x}$</td>
<td>$R^2 = 0.1249$</td>
</tr>
</tbody>
</table>

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.

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,
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, the 13 small pod data contained in the Application and five large pod TCCS data described in the AESO’s rebuttal evidence. 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 R² 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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167 Ex. 016, Application, Appendix G, Spreadsheet tab “Greenfield”, cells C3:D32
168 Ex. 016, Application, Appendix G, Spreadsheet tab “All Projects”, cells C38:D50
169 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.\textsuperscript{170} 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 R² 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.\textsuperscript{171} 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.”\textsuperscript{172} 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\textsuperscript{173} 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:

\begin{footnotesize}
\begin{enumerate}
\item Ex. 328 –Attachment to DUC.PPGA-002(c) (excel file), Tab “Classification 17”
\item Ex. 015, Application Appendix F, p. 20
\item Ex. 015, p. 21
\item AESO Argument, p 76
\end{enumerate}
\end{footnotesize}
Table 5. Results POD Cost Regression Analysis Performed by Board

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

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, 17 MW 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:

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

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, 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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\(^{174}\) AESO comments on Board Staff Proposed Cost Function, November 5, 2007
DUC had performed in conjunction with the University of Calgary Math Department (UCMD))\(^{175}\) 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.\(^{176}\) 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\(^{177}\) 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 (\textit{An }\(R^2\) \textit{of }0.51 \textit{versus }0.49\).\(^{178}\) 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.\(^{179}\) 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.

\(^{175}\) BR.AESO-001(b) of Supplemental AESO IR Responses dated November 19, 2007
\(^{176}\) DUC Reply Comments dated November 21, 2007, p. 6
\(^{177}\) DUC submission dated November 21, 2007
\(^{178}\) AESO comment letter dated November 5, 2007
\(^{179}\) DUC submission dated November 21, 2007
The Board has reviewed the DUC approach for creating a linear estimate of its power function.\textsuperscript{180} 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.\textsuperscript{181} 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>
<thead>
<tr>
<th></th>
<th>50 MW</th>
<th>60 MW</th>
<th>70 MW</th>
<th>80 MW</th>
<th>90 MW</th>
<th>100 MW</th>
<th>110 MW</th>
<th>120 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diff ($ millions)</td>
<td>1.024</td>
<td>0.978</td>
<td>0.932</td>
<td>0.886</td>
<td>0.840</td>
<td>0.794</td>
<td>0.748</td>
<td>0.702</td>
</tr>
</tbody>
</table>

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,\textsuperscript{182} 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.\textsuperscript{183} 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.\textsuperscript{184}

\textsuperscript{180} DUC submission dated November 21, 2007
\textsuperscript{181} 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.
\textsuperscript{182} AESO Argument, p. 77
\textsuperscript{183} Decision 2005-096, p. 53
\textsuperscript{184} Tr. Vol. 6, p. 1338

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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,185 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 $R^2$ 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.

185 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.\(^\text{186}\)

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 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:

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

\(^{186}\) $1,011,100 = 947,000 + (.1) \times 621,000$. 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).187

As illustrated in a table provided in its evidence,188 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 at 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.189

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

187 Ex. 239, PPGA Evidence, p. 18
188 Ex. 239, PPGA Evidence, p. 18
189 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,\(^\text{190}\) 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.\(^\text{191}\) 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.\(^\text{192}\)

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.

\(^{190}\) Ex. 012, TCCU, page 47
\(^{191}\) Ex. 225, CCA/PICA Evidence, p. 8 citing Application Appendix C (Ex. 012), p. 43
\(^{192}\) 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 thought 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.  

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
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.\footnote{Tr. Vol. 6, pp. 1209-1210} 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.\footnote{Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13- 19}

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 Boards 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.\footnote{Decision 2005-96, pp. 57-58 (Direction 13A)} 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
minimum investment allowance of $2.5 million plus an additional allowance of $100,000 per MW of project capacity.\footnote{Exhibit 007, Section 6.3.2 of the Application}

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 polices with those of the Discos and helps to preserve the
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.314

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:

314 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;\textsuperscript{315}

• 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;\textsuperscript{316}

• 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;\textsuperscript{317}

• 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;\textsuperscript{318}

• interconnection facility service characteristics and standards of functionality may change over time.\textsuperscript{319}

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.\textsuperscript{320}

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.

\textsuperscript{315} Decision 2005-096, p. 43
\textsuperscript{316} Decision 2005-096, p. 44
\textsuperscript{317} Decision 2005-096, p. 44
\textsuperscript{318} Decision 2005-096, p. 44
\textsuperscript{319} Decision 2005-096, p. 44
\textsuperscript{320} 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 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. 322 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 “nonoptional” local interconnection facilities and the cost of the nonoptional 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. 323

321 Ex. 007, pp. 28-29
322 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.
323 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).

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:

---

324 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,\(^ {325}\) 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.\(^ {326}\) 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.\(^ {327}\)
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.
2010 POD Cost Function Update
Discussion Paper

AESO 2010 Tariff Consultation

May 28, 2009
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1. Introduction
Following extensive discussion, Alberta Utility Commission (AUC) Order U2008-217 approved a number of changes to the Alberta Electric System Operator (AESO) Customer Contribution Policy and Demand Transmission Service (DTS) Point of Delivery (POD) charge rate design. Both the investment levels in the Customer Contribution Policy and the POD charge were based on a POD Cost Function.

For its 2010 General Tariff Application (GTA) the AESO proposes to review and update the POD Cost Function. All documents relating to consultation for the 2010 GTA, including the POD Cost Update, can be accessed on the AESO’s website by following the path: Tariff ► Current Consultations ► 2010 Tariff.

2. Scope
The AESO’s current POD Cost Function is based on 48 projects from the years 1987-2006. Final cost figures for most of those projects are now available. New projects have also been initiated since 2006 providing additional data for the 2010 POD Cost Function.

In reviewing the POD Cost Function, the AESO will perform the following activities.

2.1 Incorporate additional data points
The proposed approach will collect data for interconnections since the last Customer Contribution Study (filed as Appendix F to the AESO 2007 GTA on November 3, 2006). An interconnection project will be included in the update if its cost estimate is accurate to within +20%/-10% or better.

Deconstructed project information will align with the definition of Point of Delivery (POD) as utilized in the AESO’s rate design. Project costs will be escalated to 2010 dollars, appropriate to the forecast year of the tariff application.

The AESO will also include projects that are expected to be constructed in the near future or are complete and await final reconciled cost information. To date, 17 projects will be added and one project will be removed as it was cancelled.

2.2 Analyze project cost inflation
Recent data indicates that project cost is increasing and increasing at a rate higher than other general indicators such as the Consumer Price Index (CPI). The AESO will sort project cost information into various categories and apply relevant publicly available cost indices to come up with a composite price index, for comparison to the use of Alberta CPI (which was the inflation index used in the original study).

2.3 Determine raw greenfield interconnection project cost function
The AESO will collect data as outlined above and analyze it in order to determine the raw greenfield interconnection project cost function. The intent is to recommend a cost function that represents the average cost per megawatt (MW) of capacity of greenfield projects.
2.4 Compare the cost of upgrade projects to the cost of greenfield projects
The AESO will compare the cost of upgrade projects to the cost of greenfield projects to see if a cost function based on greenfield projects will reasonably represent the cost of most upgrade projects. Information from 64 upgrade projects will be used for this comparison.

3. Methodology Overview

3.1 Availability of Data
This analysis will exclude dual use projects (both DTS and Supply Transmission Service, STS), projects for generators (STS) only, and projects partially owned by the Customer. In other words this analysis will include load (DTS) only projects with no customer ownership. Dual use facilities are typically built to accommodate a larger generator capacity. STS interconnections are not charged POD costs on a monthly basis and do not receive investment. The AESO does not have the cost data for customer owned facilities.

The preliminary analysis component of the update will utilize historical data to determine individual cost components of the project costs. This information primarily comes from the final cost data submitted by the Transmission Facility Owners (TFOs). Where final reconciled costs or their allocations are unavailable, individual cost components will be determined using the estimated costs per Proposal to Provide Service (PPS) documents.

Data will be drawn from AESO-maintained Customer Access Services Project Information Resource (CASPIR) and Transmission Administration System Model (TASMo) databases. In addition, project information will be extracted from internal Customer Contribution determinations and other project information documentation.

Where reliable cost information is not available, the project will be excluded from the update.

3.2 Project and Category Classification
The AESO identifies each interconnection proposal as a “Project” and assigns project identifications on a numerical basis. All project information is maintained both electronically and in hard copy, in numerically ordered project files. Project files are filed by their assigned number.

The classification of system and customer-related costs is as outlined in Article 9 of the AESO’s Terms and Conditions. When project costs are determined, the AESO allocates these costs to the system or the customer, based on the nature of the project. For load customers, customer-related costs are the costs associated with the construction project, entailing radial transmission extensions and enhancements at adjacent substations. These costs can normally include the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer’s interconnection.
System-related costs are those project costs associated with looped transmission facilities, radial transmission lines that will become looped within five years, or in any circumstance where the AESO deems that for economics or system planning purposes a facility larger than that required to serve the customer is necessary. In those cases, the AESO classifies these portions of the project as system-related costs.

Customer-related costs are those costs that the customer is responsible for, and include standard facility costs and those costs that are deemed in excess of standard facility costs. AESO standard facilities are the least-cost interconnection facilities which meet good transmission practice, including reliability, protection and operating criteria and standards. These generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection. Standard facilities for any interconnection proposal meet the forecasted load requirements for that interconnection. Standard facility costs are the only costs eligible for investment under the AESO Tariff.

Cost in excess of standard facilities are those costs that exceed the cost of the AESO deemed standard facility interconnection configurations. For example, customer preferences to construct facilities that are larger or provide more capacity than is deemed necessary by the AESO are in excess of standard facility costs. The customer is responsible for paying all customer costs in excess of AESO standard facility costs, and these costs are not eligible for AESO investment.

Figure 1 illustrates the cost determination process for new load projects.

Figure 1
4. Data Collection

4.1 New Projects

Table 1 lists information gathered for each project. For the “year” category, the AESO notes that the year recorded is the year in which the most recent cost estimate or actuals were received or the dollar year mentioned in such most recent document. This assumption minimizes the effect of project construction spanning several years. The AESO recognizes that cost estimates change over time, but also assumes that the most recently submitted costs reflect costs incurred “to date” on a project, and likely are a better indicator of construction-in-progress dollars. At this time final costs for 42 out of 64 projects are known.

The AESO will compile 17 new projects since the last Customer Contribution Study that had Customer Contribution determinations associated with their projects and had applied for DTS contracts or contract increases.

Table 1 – Project Information

<table>
<thead>
<tr>
<th>Information Category</th>
<th>Source of Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project #</td>
<td>Internally assigned project numbers</td>
</tr>
<tr>
<td>Project Name</td>
<td>The name associated with the project</td>
</tr>
<tr>
<td>TFO</td>
<td>The Transmission Facility Owner associated with the project</td>
</tr>
<tr>
<td>Project Description</td>
<td>A brief outline of the nature of the project</td>
</tr>
<tr>
<td>Year</td>
<td>The recorded year is the year in which actual costs were reconciled, or where unavailable the year of most recent PPS submittal.</td>
</tr>
<tr>
<td>Present Value Factor</td>
<td>Calculated using Alberta CPI values to 2008, and recent Conference Board of Canada values for 2009 and 2010.</td>
</tr>
<tr>
<td>AESO Standard Facility Costs</td>
<td>The AESO Standard Facility costs as identified in most recent customer contribution determination</td>
</tr>
<tr>
<td>DTS Contract Capacity</td>
<td>The DTS Contract Capacity as identified in most recent customer contribution determination</td>
</tr>
</tbody>
</table>

Other considerations of note include use of the Alberta CPI for inflation rates. The AESO proposes that historical Alberta CPI (from StatCan) will be utilized for years 1987 through 2008. For years 2009 and 2010, the AESO proposes to utilize Alberta CPI as estimated by the Conference Board of Canada in the spring of 2009.

4.2 Inflation

During 2008, AltaLink led a stakeholder process to identify industry concerns with the AESO's customer contribution policy and deliver recommendations for change. These recommendations are available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff, in the document titled AltaLink Stakeholder Process - Recommendations. One of the recommendations was to “use an inflation factor that is representative of the Alberta market place, and incorporate a mechanism to adjust the contribution formula to account for regulatory lag”. The cross-
industry stakeholder working group stated that “The AESO customer contribution formula is based on actual project costs escalated at CPI. However, the CPI escalator is significantly lower than actual transmission cost escalation rates in Alberta. The net result is increased contributions for most interconnections. Regulatory lag is further complicating this problem, which can result in a single contribution formula being in place for 2-3 years. In addition, the cycle time to build a transmission interconnection is reaching lengths of 2-4 years”. In support of this statement the group provided an appendix determining the transmission cost escalation rate to be 9% for 2006-2007 as compared to a CPI escalator of 5%. The group recommended that “The AESO include an annual automatic escalator within the contribution policy, and that this should be tied to a published index” and “The AESO should also adopt an inflation factor which is reflective of transmission costs in Alberta”.

The AESO agrees with the concept of escalating the maximum local investment using public index/indices between full tariff applications. The AESO will perform an analysis to determine an appropriate escalator for the customer interconnection project cost. The AESO will examine the project data to establish appropriate cost categories and corresponding public indices. The AESO will divide the project cost between substation related material, transmission line related material, engineering, and construction. The Canada-wide “Equipment (v735305)” index from Statistics Canada will be used for escalating substation related material cost. The Canada-wide “Materials (v735258)” index from Statistics Canada will be utilized for escalating transmission line related material cost. The Alberta-wide “Industrial services (v92756)” index from Statistics Canada will be used to escalate engineering related cost. The Average of “Total, industrial structures (v7717851)” and “Total, industrial structures (v7717855)” from Statistics Canada, for Calgary and Edmonton respectively, will be used to escalate construction cost. Weighting the cost in each category by the corresponding escalator provides a composite escalator. When an index value for the year is unavailable, the average of values for the last five years will be used.

The average value of the composite escalator from 1987-2007 is 3.3% while the average value of an escalator based on Alberta CPI is 3.0%. The composite escalator reaches a maximum of 10.1% in 2007 and a minimum of (4.33%) in 1991 while the escalator based on Alberta CPI reaches a maximum of 5.87% in 1991 and a minimum of 0.99% in 1993. For eight years the increase in Alberta CPI is higher than the increase in the Composite Price Index. This information can be found in the “escalator” tab of the supporting Excel workbook. Table 1 below shows the escalator values for 1987-2007.
Table 2 - Escalator Values

<table>
<thead>
<tr>
<th>Year</th>
<th>% Year Over Year Increase in Alberta CPI</th>
<th>% Year Over Year Increase in Composite Price Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>1987</td>
<td>4.08</td>
<td>4.89</td>
</tr>
<tr>
<td>1988</td>
<td>2.71</td>
<td>6.11</td>
</tr>
<tr>
<td>1989</td>
<td>4.11</td>
<td>9.06</td>
</tr>
<tr>
<td>1990</td>
<td>5.78</td>
<td>2.31</td>
</tr>
<tr>
<td>1991</td>
<td>5.87</td>
<td>-4.33</td>
</tr>
<tr>
<td>1992</td>
<td>1.51</td>
<td>0.54</td>
</tr>
<tr>
<td>1993</td>
<td>0.99</td>
<td>1.77</td>
</tr>
<tr>
<td>1994</td>
<td>1.47</td>
<td>3.19</td>
</tr>
<tr>
<td>1995</td>
<td>2.30</td>
<td>4.26</td>
</tr>
<tr>
<td>1996</td>
<td>2.25</td>
<td>0.45</td>
</tr>
<tr>
<td>1997</td>
<td>1.97</td>
<td>2.61</td>
</tr>
<tr>
<td>1998</td>
<td>1.25</td>
<td>3.90</td>
</tr>
<tr>
<td>1999</td>
<td>2.47</td>
<td>0.96</td>
</tr>
<tr>
<td>2000</td>
<td>3.39</td>
<td>2.99</td>
</tr>
<tr>
<td>2001</td>
<td>2.33</td>
<td>4.88</td>
</tr>
<tr>
<td>2002</td>
<td>3.41</td>
<td>1.74</td>
</tr>
<tr>
<td>2003</td>
<td>4.40</td>
<td>-2.81</td>
</tr>
<tr>
<td>2004</td>
<td>1.44</td>
<td>4.42</td>
</tr>
<tr>
<td>2005</td>
<td>2.08</td>
<td>4.80</td>
</tr>
<tr>
<td>2006</td>
<td>3.89</td>
<td>7.55</td>
</tr>
<tr>
<td>2007</td>
<td>4.99</td>
<td>10.09</td>
</tr>
<tr>
<td>Average</td>
<td>2.99</td>
<td>3.30</td>
</tr>
<tr>
<td>High</td>
<td>5.87</td>
<td>10.09</td>
</tr>
<tr>
<td>Low</td>
<td>0.99</td>
<td>-4.33</td>
</tr>
</tbody>
</table>

The AESO considers that appropriate criteria for selecting an index are:
1) Availability of credible public forecast,
2) Level of volatility, and
3) Likelihood of a year over year decrease.

The AESO needs the forecasted index values to inflate the project cost to the test year. It may take up to two years for the AUC to approve an AESO application, and thus the AESO needs the forecasted index values for at least two future years. The AESO expects to update the investment level using forecasted index values on an annual basis along with a rates update application between GTAs. For this reason an index for which a credible public forecast is available is preferable.

If the index is very volatile then it may affect customer behavior resulting in advancement or delay of the customer interconnection projects thus adversely affecting the related workflow. The issue may be compounded by the fact that index value may decrease year over year thus resulting in a reduction in the investment level.

Over 1987-2007 Alberta CPI values are not, on average, very different from the Composite Price Index values. Price indices that make up the Composite Price Index are not forecasted while Alberta CPI forecasts are available. The Composite Price Index is
more volatile, has higher peaks and lower troughs, and was negative in two years (1991 and 2003). In light of above discussion AESO proposes that project costs should be inflated using Alberta CPI.

The AESO also assessed the differences that would result from using Alberta CPI rather than the Composite Price Index for the POD Cost Function developed in the remainder of this paper. The table below compares the tier values from page 13 of this paper, which result from using Alberta CPI for escalation, to values that would result from using the Composite Price Index.

**Table 3 – Tier Values for Alberta CPI and Composite Price Index**

<table>
<thead>
<tr>
<th>Tier</th>
<th>Alberta CPI</th>
<th>Composite Price Index</th>
<th>Increase/(Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed</td>
<td>0.852</td>
<td>1.07076</td>
<td>25.68%</td>
</tr>
<tr>
<td>First 7.5 MW</td>
<td>0.636</td>
<td>0.779</td>
<td>22.45%</td>
</tr>
<tr>
<td>Next 9.5 MW</td>
<td>0.243</td>
<td>0.295</td>
<td>21.32%</td>
</tr>
<tr>
<td>Next 23 MW</td>
<td>0.149</td>
<td>0.180</td>
<td>20.84%</td>
</tr>
<tr>
<td>Remaining MW</td>
<td>0.083</td>
<td>0.099</td>
<td>20.27%</td>
</tr>
<tr>
<td><strong>Average Increase</strong></td>
<td></td>
<td></td>
<td><strong>22.11%</strong></td>
</tr>
</tbody>
</table>

The Tier values go up on average by about 22.1% and the increase is consistent over all Tiers. The reason for this substantial increase is that for 2004-2007 the increase in Composite Price Index is quite higher than the increase in Alberta CPI. It should be noted that for years 2008-2010, the Composite Price Index value was estimated as the average of five preceding values. This may not be a very accurate estimate because of the recent economic downturn that may result in 2008-2010 values being quite lower than 2005-2007 values and thus limiting the increase considerably. The shape of the POD Cost Function does not fundamentally change when the Composite Price Index is used, and therefore the DTS POD charge would not be expected to change as the individual POD charge tier amounts are effectively prorated from the cost function to recover the POD-related revenue requirement.

With respect to forecasting the Composite Price Index for future years, one way to do so would be to take the rolling average of index values in three or five preceding years as the forecasted index value for the upcoming year. Table 4 below shows the results of such an approach.
### Table 4 – Forecast Using Rolling Average Approach

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual Index Value</th>
<th>Three Year Rolling Average</th>
<th>Difference Between Actual and Three Year Rolling Average</th>
<th>Five Year Rolling Average</th>
<th>Difference Between Actual and Five Year Rolling Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>1987</td>
<td>4.89</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1988</td>
<td>6.11</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1989</td>
<td>9.06</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1990</td>
<td>2.31</td>
<td>6.68</td>
<td>-4.37</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1991</td>
<td>-4.33</td>
<td>5.83</td>
<td>-10.16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1992</td>
<td>0.54</td>
<td>2.35</td>
<td>-1.80</td>
<td>3.61</td>
<td>-3.06</td>
</tr>
<tr>
<td>1993</td>
<td>1.77</td>
<td>-0.49</td>
<td>2.27</td>
<td>2.74</td>
<td>-0.96</td>
</tr>
<tr>
<td>1994</td>
<td>3.19</td>
<td>-0.67</td>
<td>3.86</td>
<td>1.87</td>
<td>1.32</td>
</tr>
<tr>
<td>1995</td>
<td>4.26</td>
<td>1.83</td>
<td>2.43</td>
<td>0.70</td>
<td>3.57</td>
</tr>
<tr>
<td>1996</td>
<td>0.45</td>
<td>3.08</td>
<td>-2.62</td>
<td>1.09</td>
<td>-0.64</td>
</tr>
<tr>
<td>1997</td>
<td>2.61</td>
<td>2.63</td>
<td>-0.02</td>
<td>2.04</td>
<td>0.57</td>
</tr>
<tr>
<td>1998</td>
<td>3.90</td>
<td>2.44</td>
<td>1.45</td>
<td>2.46</td>
<td>1.44</td>
</tr>
<tr>
<td>1999</td>
<td>0.96</td>
<td>2.32</td>
<td>-1.36</td>
<td>2.88</td>
<td>-1.92</td>
</tr>
<tr>
<td>2000</td>
<td>2.99</td>
<td>2.49</td>
<td>0.49</td>
<td>2.44</td>
<td>0.55</td>
</tr>
<tr>
<td>2001</td>
<td>4.88</td>
<td>2.62</td>
<td>2.26</td>
<td>2.18</td>
<td>2.70</td>
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<tr>
<td>2002</td>
<td>1.74</td>
<td>2.94</td>
<td>-1.21</td>
<td>3.07</td>
<td>-1.33</td>
</tr>
<tr>
<td>2003</td>
<td>-2.81</td>
<td>3.20</td>
<td>-6.01</td>
<td>2.89</td>
<td>-5.70</td>
</tr>
<tr>
<td>2004</td>
<td>4.42</td>
<td>1.27</td>
<td>3.15</td>
<td>1.55</td>
<td>2.87</td>
</tr>
<tr>
<td>2005</td>
<td>4.80</td>
<td>1.12</td>
<td>3.68</td>
<td>2.24</td>
<td>2.55</td>
</tr>
<tr>
<td>2006</td>
<td>7.55</td>
<td>2.14</td>
<td>5.42</td>
<td>2.60</td>
<td>4.95</td>
</tr>
<tr>
<td>2007</td>
<td>10.09</td>
<td>5.59</td>
<td>4.50</td>
<td>3.14</td>
<td>6.95</td>
</tr>
</tbody>
</table>

It is clear that such an approach may not provide a reasonable forecast. Using a three year and five year rolling average approach the difference between the forecasted and actual value may be as large as -10.16% and 6.95% respectively which seems to negate any benefit that may have resulted from the use of this interconnection project specific index.

### 5. Analysis

#### 5.1 Construction

The analysis will consider data from a total of 64 projects initiated during the 1987-2009 period. All of these projects are load-serving and have Customer Contribution determinations (except for the 18 historical projects included as a result of Decision 2007-106). Information from the Customer Contribution determinations will be extracted for each of these projects.

Figure 2 shows the relationship between the AESO Standard Facilities determinations and DTS contract capacity. The currently approved POD Cost Function is also provided for comparison purposes. This figure and source data can be found in the “raw-cost-function” and “projects” tabs of the Excel workbook respectively.
The trend line equation represented is $y = 2.4104 \times x^{0.4204}$ and it has correlation of $r^2 = 0.4211$.

The projects in the data set exhibit significant variability or “scatter”. For example, three projects near 19 MW capacity had project costs of $5.8, $16.5 and $30.2 million. The variability reflects different amounts of radial line required for interconnection, different substation configurations, varying geography and construction conditions, and varying levels of complexity for each interconnection.

5.2 Cost Function Determination

Table 5 summarizes the cost functions that demonstrated the highest correlation in the update.
Table 5 – Cost Function

Original cost function based on 48 projects from 1987-2006

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>( r^2 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (Power)</td>
<td>( y = 2.2131 \times x^{0.3717} )</td>
<td>0.4941</td>
</tr>
</tbody>
</table>

Updated functions based on 64 projects from 1987-2009

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>( r^2 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed (Power)</td>
<td>( y = 2.4104 \times x^{0.4204} )</td>
<td>0.4211</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>( y = 2.7874 \times \ln(x) + 1.469 )</td>
<td>0.2368</td>
</tr>
<tr>
<td>Linear</td>
<td>( y = 0.102 \times x + 6.5968 )</td>
<td>0.1419</td>
</tr>
<tr>
<td>Exponential</td>
<td>( y = 5.4301 \times e^{0.0134 \times x} )</td>
<td>0.1911</td>
</tr>
<tr>
<td>Cubic</td>
<td>( y = 7E-05 \times x^3 - 0.0135 \times x^2 + 0.7368 \times x + 1.0925 )</td>
<td>0.3155</td>
</tr>
<tr>
<td>Quadratic</td>
<td>( y = -0.0021 \times x^2 + 0.3166 \times x + 4.1734 )</td>
<td>0.2232</td>
</tr>
</tbody>
</table>

As in the original POD Cost Function determination, the power function has the highest regression coefficient of 0.4211, which indicates moderate positive correlation between project costs and DTS capacity. The function is very similar to the POD Cost Function approved in Decision 2007-106. The AESO believes that the power cost function provides the best representation of the project costs, as follows:

\[
\text{Average cost} = 2.4104 \times (\text{DTS Capacity})^{0.4204}
\]

Although the variability of costs within the data set is significant, the projects nevertheless exhibit a clear trend of cost increasing as capacity increases. Combined with the moderate regression coefficient, the AESO concludes this equation is a reasonable average cost function for recent transmission interconnections.

5.3 Raw Cost Function

The complete derivation of the proposed POD cost function is summarized as follows:

(a) As discussed in the preceding section, the average cost function for the data is reproduced, and determined to be:

\[
\text{Equation 1} \\
\text{Average cost} = 2.4104 \times (\text{DTS Capacity})^{0.4204}
\]

(b) Fitting a series of linear functions to replicate the slopes of the power function for 0.1, 7.5 MW, 17 MW, 40 MW, and 122.8 MW points results in a cost function which is a summation of five terms. 0.1 MW is the smallest project size while 122.8 MW is the largest project size. Breakpoints of 7.5 MW, 17 MW, and 40 MW will be used consistent with the approach approved in Decision 2007-106.
(c) The AESO therefore recommends the following cost function:

**Equation 2**
Recommended Cost = $0.852 million
+ ($0.636 million/MW × first 7.5 MW of DTS Capacity)
+ ($0.243 million/MW × next 9.5 MW of DTS Capacity)
+ ($0.149 million/MW × next 13 MW of DTS Capacity)
+ ($0.083 million/MW × remaining MW of DTS Capacity)

The AESO considers the recommended cost function (Equation 2) to appropriately reflect project costs for the purposes of establishing investment levels and for rate design in the AESO’s Tariff. This information can be found in the “cost-function” tab of the Excel workbook.

The recommended cost function will be developed using data for load-only projects. Where a project provided interconnection of both load and generation or of multiple loads, the cost function must be adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. The AESO therefore proposes that the recommended cost function incorporate the substation fraction (“SF”) into each tier as follows:
Equation 3
DTS POD Cost = $0.852 million x SF
+ $0.636 million/MW × first (7.5 multiplied by the SF) MW of DTS Capacity
+ $0.243 million/MW × next (9.5 multiplied by the SF) MW of DTS Capacity
+ $0.149 million/MW × next (23 multiplied by the SF) MW of DTS Capacity
+ $0.083 million/MW × remaining MW of DTS Capacity

5.4 Reasonability
AESO tested the reasonableness of these results by comparing them with the current DTS POD costs and the close match suggests that the equation above is a reasonable representation of average POD costs. Consistent and proportionate increases in all five terms of the cost function indicates that all costs have risen since the last study.

5.5 Upgrades
The AESO will investigate whether projects that involve upgrades to existing PODs have a different relation between upgrade cost and incremental DTS capacity. Unit cost of these upgrade projects will be plotted against the average of the DTS capacity before and after the upgrade. Then greenfield projects will be grouped according to their DTS capacity of 0-7.5 MW, 7.5-17 MW, 17-40 MW, and 40 MW and larger. The average cost of each group will be plotted resulting in four blocks. This information can be found in the “upgrade-projects” tab of the Excel workbook.

Figure 4
Average AESO Standard Cost of Upgrade Projects and Greenfield Projects
The AESO considers that the proposed cost function though based on the data from greenfield projects sufficiently reflects the cost of most upgrade projects.

5.6 Primary Service Credit
Currently the Primary Service Credit (PSC) determination is based on the division of cost of interconnection between substation related costs and line related costs. The AESO will include interconnection project cost information that has become available since the last PSC determination to update the abovementioned division. Greenfield projects for which such division is available will be used for the calculation. The ratio of total substation related cost (that is, excluding line related cost) to total AESO standard cost was calculated to be 0.55 in the last study. This ratio currently stands at 0.56. This information can be found in the “psc” tab of the Excel workbook.

6. Conclusion
The AESO believes this update meets the requirements of Decision 2007-106 and provides an updated POD Cost Function.

The AESO notes that the interconnection project construction costs showed moderate correlations with DTS contract capacities ($r^2=0.4212$).

The proposed cost function equation is based on the establishment of a fixed component of the cost function. The fixed component represents costs a customer cannot avoid regardless of what decisions the customer makes.

The resulting POD Cost Function is:

**Equation 4**

DTS POD Cost = $0.852 \text{ million} \times SF + $0.636 \text{ million/MW} \times \text{first (7.5 multiplied by the SF) MW of DTS Capacity} + $0.243 \text{ million/MW} \times \text{next (9.5 multiplied by the SF) MW of DTS Capacity} + $0.149 \text{ million/MW} \times \text{next (23 multiplied by the SF) MW of DTS Capacity} + $0.083 \text{ million/MW} \times \text{remaining MW of DTS Capacity}$
<table>
<thead>
<tr>
<th>Project #</th>
<th>Project Name</th>
<th>TFO</th>
<th>Project Description</th>
<th>Cost Estimate Year</th>
<th>AESO Standard Cost</th>
<th>DTS (MW)</th>
<th>Substation Related Cost</th>
<th>Line Related Cost</th>
<th>Engineering Related Cost</th>
<th>Construction Related Cost</th>
<th>Escalated AESO Standard Cost Using AB CPI ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Brintnell ATCO</td>
<td></td>
<td>Britnell sub, Wabasca modifications, Ruth Lake Relay and I</td>
<td>1990 $1,076,036</td>
<td>1.09</td>
<td>0.1</td>
<td>1.79</td>
<td>1.397</td>
<td>1.103</td>
<td>1.39</td>
<td>1.924</td>
</tr>
<tr>
<td>10</td>
<td>Algar and Mariana ATCO</td>
<td></td>
<td>2 new subs and transmission lines</td>
<td>1990 $583,613</td>
<td>1.09</td>
<td>1.5</td>
<td>1.103</td>
<td>1.397</td>
<td>1.103</td>
<td>1.39</td>
<td>1.924</td>
</tr>
<tr>
<td>34</td>
<td>Lloydminster ATCO</td>
<td></td>
<td>New substation, transformer and breakers</td>
<td>1990 $835,903</td>
<td>1.09</td>
<td>4.1</td>
<td>6.106</td>
<td>2.970</td>
<td>1.970</td>
<td>2.97</td>
<td>3.967</td>
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<tr>
<td>44</td>
<td>Foster Creek ATCO</td>
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<td>New substation with two customers</td>
<td>1990 $3,869,473</td>
<td>1.09</td>
<td>4.2</td>
<td>2.970</td>
<td>7.026</td>
<td>7.026</td>
<td>7.02</td>
<td>9.033</td>
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<tr>
<td>79</td>
<td>Creek Lake ATCO</td>
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<td>2 new subs and transmission lines</td>
<td>1990 $2,688,121</td>
<td>1.09</td>
<td>5.6</td>
<td>3.796</td>
<td>2.148</td>
<td>2.148</td>
<td>2.14</td>
<td>2.984</td>
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<td>80</td>
<td>Flat Lake UNC</td>
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<td>New substation and associated transmission</td>
<td>1990 $2,565,464</td>
<td>1.09</td>
<td>6.6</td>
<td>4.774</td>
<td>2.486</td>
<td>2.486</td>
<td>2.48</td>
<td>3.184</td>
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<tr>
<td>170</td>
<td>UNC Terrace Expansion UNC</td>
<td></td>
<td>Large project including construction of 2 substations, upgra</td>
<td>1990 $7,593,043</td>
<td>1.09</td>
<td>56.8</td>
<td>12.685</td>
<td>10.280</td>
<td>10.280</td>
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<td>13.445</td>
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<td>230</td>
<td>Kinosi ATCO</td>
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<td>Construction of 240kV substation with transformers and bre</td>
<td>1990 $5,058,000</td>
<td>1.09</td>
<td>18.0</td>
<td>6.550</td>
<td>5.777</td>
<td>5.777</td>
<td>5.77</td>
<td>7.244</td>
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<tr>
<td>308</td>
<td>ENMAX 26S substation mod ENMAX</td>
<td></td>
<td>ENMAX 26S New Substation Construction to accommodate</td>
<td>1990 $5,067,806</td>
<td>1.09</td>
<td>10.0</td>
<td>5.654</td>
<td>4.658</td>
<td>4.658</td>
<td>4.65</td>
<td>5.540</td>
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<tr>
<td>324</td>
<td>Pinedale AltaLink</td>
<td></td>
<td>Substation, installation of 25kV circuit breaker, bus extens</td>
<td>1990 $5,095,965</td>
<td>1.09</td>
<td>12.0</td>
<td>5.686</td>
<td>4.540</td>
<td>4.540</td>
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<td>5.400</td>
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<tr>
<td>333</td>
<td>ENMAX #7 Sub (new) ENMAX</td>
<td></td>
<td>New 138/25kV substation to accommodate load growth</td>
<td>1990 $5,095,000</td>
<td>1.09</td>
<td>12.0</td>
<td>5.686</td>
<td>4.540</td>
<td>4.540</td>
<td>4.54</td>
<td>5.400</td>
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<tr>
<td>340</td>
<td>EnCanA Countless AltaLink</td>
<td></td>
<td>New 138/16.1kV source substation with two 15/20/25 MVA</td>
<td>1990 $7,469,005</td>
<td>1.09</td>
<td>17.7</td>
<td>6.060</td>
<td>4.980</td>
<td>4.980</td>
<td>4.98</td>
<td>5.860</td>
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<tr>
<td>343</td>
<td>Bassoano Substation AML</td>
<td></td>
<td>New Bassoano 138/25kV substation to serve growing load it</td>
<td>1990 $5,131,301</td>
<td>1.09</td>
<td>22.0</td>
<td>9.980</td>
<td>7.980</td>
<td>7.980</td>
<td>7.98</td>
<td>9.880</td>
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<tr>
<td>345</td>
<td>Joslyn ATCO</td>
<td></td>
<td>New 240/25kV substation and t-tap</td>
<td>1990 $5,469,005</td>
<td>1.09</td>
<td>24.0</td>
<td>9.980</td>
<td>7.980</td>
<td>7.980</td>
<td>7.98</td>
<td>9.880</td>
</tr>
<tr>
<td>358</td>
<td>Fortis - Bretona Substation AML</td>
<td></td>
<td>New Substation (138kv/25kv) to accommodate load growth</td>
<td>1990 $4,512,930</td>
<td>1.09</td>
<td>18.0</td>
<td>5.035</td>
<td>4.035</td>
<td>4.035</td>
<td>4.03</td>
<td>4.995</td>
</tr>
<tr>
<td>360</td>
<td>Fortis - Viscount (St. Albert) AML</td>
<td></td>
<td>New Substation (138kv/25kv) to accommodate load growth</td>
<td>1990 $5,067,806</td>
<td>1.09</td>
<td>20.0</td>
<td>5.854</td>
<td>4.658</td>
<td>4.658</td>
<td>4.65</td>
<td>5.540</td>
</tr>
<tr>
<td>385</td>
<td>ATCO Terasen Ribstone Cre ATCO</td>
<td></td>
<td>Install three 138kv breakers at Monitor 744S, construct 60k</td>
<td>1990 $3,578,958</td>
<td>1.09</td>
<td>7.5</td>
<td>4.658</td>
<td>3.540</td>
<td>3.540</td>
<td>3.54</td>
<td>4.234</td>
</tr>
<tr>
<td>386</td>
<td>Terasen - Wardlow/Jenner AML</td>
<td></td>
<td>New load (3 to 6MW) at Jenner Station. 25kv breaker and 2</td>
<td>1990 $6,546,597</td>
<td>1.09</td>
<td>9.0</td>
<td>7.304</td>
<td>6.930</td>
<td>6.930</td>
<td>6.93</td>
<td>8.004</td>
</tr>
<tr>
<td>387</td>
<td>Terasen - Peace Butte Station AML</td>
<td></td>
<td>New load of 6MW at Peace Butte Stn. Install two 138kv bre</td>
<td>1990 $6,211,359</td>
<td>1.09</td>
<td>7.5</td>
<td>6.930</td>
<td>5.940</td>
<td>5.940</td>
<td>5.94</td>
<td>7.054</td>
</tr>
<tr>
<td>420</td>
<td>Air Products Edmonton Refin AML</td>
<td></td>
<td>New substation facilities to supply 15MVA of new load</td>
<td>1990 $6,331,000</td>
<td>1.09</td>
<td>10.0</td>
<td>3.940</td>
<td>3.540</td>
<td>3.540</td>
<td>3.54</td>
<td>4.234</td>
</tr>
<tr>
<td>422</td>
<td>TransCanada Edson Gas AML</td>
<td></td>
<td>New Marlboro 138/16.1kV Substation to support cust</td>
<td>1990 $7,719,583</td>
<td>1.09</td>
<td>24.0</td>
<td>7.954</td>
<td>6.903</td>
<td>6.903</td>
<td>6.90</td>
<td>7.843</td>
</tr>
<tr>
<td>425</td>
<td>ENMAX No. 6 Substation ENMAX</td>
<td></td>
<td>New 138kV distribution point of delivery to address DFO re</td>
<td>1990 $5,955,000</td>
<td>1.09</td>
<td>16.0</td>
<td>6.903</td>
<td>5.883</td>
<td>5.883</td>
<td>5.88</td>
<td>6.773</td>
</tr>
<tr>
<td>433</td>
<td>Fortis Christina Lake AML</td>
<td></td>
<td>New 240 / 25kV Substation (40MW load), 240kV modification</td>
<td>1990 $28,844,000</td>
<td>1.09</td>
<td>25.0</td>
<td>33.433</td>
<td>26.703</td>
<td>26.703</td>
<td>26.70</td>
<td>30.663</td>
</tr>
</tbody>
</table>
2002-2009 Customer Interconnection Upgrade Projects

<table>
<thead>
<tr>
<th>Project #</th>
<th>Project Name</th>
<th>TFO</th>
<th>Description</th>
<th>Cost Estimate</th>
<th>ASEO Standard Cost</th>
<th>DTS (MW)</th>
<th>Substation Related Cost</th>
<th>Line Related Cost</th>
<th>Engineering Related Cost</th>
<th>Construction Related Cost</th>
<th>Escalated AEO Standard Cost Using AB CPI ($MW)</th>
<th>DTS Increase (MW)</th>
<th>Pre-Upgrade DTS (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>178</td>
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<td>Norcen-812S 144/25 kV Stati-ATCO</td>
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<td>Station upgrade to meet load growth.</td>
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<td>St. Albert</td>
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<td>Install new 25/33/42 MVA transformer and new 25kV circuit breaker.</td>
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<td>Installation of 25kV circuit breaker, protection and control, 2002</td>
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<td>Fortis - Suffield 895S AML</td>
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<td>PH I - Regulator upgrade, feeder addition, PH II - transformer for relocation and upgrade of service</td>
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<td>25kV circuit breaker at Acheson 305S</td>
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<td>25kV breaker addition at Stony plain 434S</td>
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<td>Blackfalds</td>
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<td>25kV breaker addition at Blackfalds 196S</td>
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<td>Whitecourt</td>
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<td>25kV breaker addition at Whitecourt</td>
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<td>368</td>
<td>Leming Lake - 715</td>
<td>ATCO</td>
<td>Transmission facilities to accommodate 15MW load of SAG</td>
<td>$2,812,615</td>
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<td>Gainsford</td>
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<td>Replace existing 31MVA transformer with a 10MVA transformer</td>
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<td>Fort Saskatchewan</td>
<td>AltaLink</td>
<td>Installation of 25kV breaker</td>
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<td>Air Liqine 337s AML</td>
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<td>Transformer addition to support load growth.</td>
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<td>Britnell Expansion</td>
<td>AltaLink</td>
<td>Install two 25kV breakers, a bus tie MOD, and a 25kV gang breaker</td>
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<td>Oven - 767S Substation cap:ATCO</td>
<td>AltaLink</td>
<td>Upgrades (fans, regulator)</td>
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<td>Fortis-Ross Creek 9065 Capi AML</td>
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<td>Transformer addition to meet load growth.</td>
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<td>Canmore Upgrade</td>
<td>AltaLink</td>
<td>Addition of 138/25kV 25 MVA transformer</td>
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<td>456</td>
<td>ATCO Seal Lake 869s Cap:ATCO</td>
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<td>Transformer addition to meet load growth.</td>
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<td>483</td>
<td>Coaldale</td>
<td>AltaLink</td>
<td>Installation of 138/25kV transformer and new motor operator</td>
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<td>484</td>
<td>Updike</td>
<td>ATCO</td>
<td>30km of new 138 kV transmission line and new 144/2SK v:</td>
<td>$11,880,000</td>
<td>43.00</td>
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<td>Namaka</td>
<td>AltaLink</td>
<td>New 25/33/42 MVA transformer and bus work</td>
<td>$2,698,393</td>
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804
806
823

ATCO Kinosis - 25 kV breake ATCO
Fortis Innisfail Breaker
AML
Fort Assiniboine 234S
AML
ATCO Ruth Lake 848S CapacATCO
Cranberry Lake
ATCO
Air Products Bretville
AML
Mariana Lake
ATCO
ATCO Bridge Creek
ATCO
EPCOR Petrolia
ETI
Enmax Feeder Addition
ENMAX
Fortis - Tilley
AML
Enbridge - Rosyth
AML
Fortis- Balzac
AML
Fortis - Stavely
AML
Fortis - Empress
AML
Fortis - Red Deer
AML
Fortis - Devon
AML
Fort Assiniboine
AML
IOL
AML
ATCO Hangingstone
ATCO
ENMAX 7S
ENMAX
Acheson
AML
Fort Saskatchewan
AML
Fortis- Bruderheim
AML
ATCO/AML
Fortis - Edgerton
AML
Fortis - Peace Butte
AML
Shell
AML
ATCO - Michichi
ATCO
Fortis - Blackmud
AML
Fortis - Wainwright
AML
ATCO - three hills
ATCO
ATCO - Dome Cutbank
ATCO
ATCO - Ethel Lake
ATCO
ATCO - Crow Lake
ATCO
ATCO - Mahihkan
ATCO
ATCO - Mercer Hill
ATCO
Fortis - Dry Creek
AML
Fortis - Northwest Cardiff
AML
Fortis - Hayter
AML
Enmax - 26
ENMAX

Add a 25 Kv breaker for new ATCO feeder to accommodat
New 25kV breaker addition at Innisfail 214S to accommoda
Temporary replacement of existing 7.5MVA transformer wit
Transformer addition to meet load growth.
New transformer
Substation (prior) and transformer (new)
New regulators
Transformer replacement
New beaker
Addition of one feeder originating at No. 37 Substation.
Install a second 138 kV/25 kV supply transformer and 25 kV
Transformer addition to Enbridge Rosyth 296S.
Installation of a second 138kV/25kV, 25/33/42 MVA supply
Replace existing 12/13.5 MVA transformer and 15MVA 25 k
New regulator
New regulator
Upgrade overhead conductor from 3/0 to 477 MCM
lnstall an additional 138/25 kV 15/20/25 MVA LTC transform
Thermal Upgrade of the line
Addition of one 144kV breaker, 1-42 MVA 144/25 kV transf
Transformer addition at Enmax # 7 sub due to load growth
new breaker
25 kV breaker addition at Fort Saskatchewan 54S Sub.
Addition of a 15/20/25 MVA transformer at Bruderheim
Service for 8MW Pump Station in the Vermillion Area DTS
Upgrade 138kV transformer to 15/20/25 MVA LTC
Addition of 138/25kV 15/20/25 MVA transformer and 25 kV
Install a T-Tap from 807L to Customer owned 402S Substa
25kV breaker additions at Michichi Creek 802S
Upgrade to 155S including one 138/25kV transformer and t
Fortis Alberta Wainwright 138-25kV Transformer Addition
25kV Breaker Addition
Regulator Upgrade due to DFO load growth
Capacity Upgrade - New 144/25kV transformer to replace 1
Breaker addition (25kV) to existing crow substation
25kV Breaker Addition
Transformer upgrade
Transformer addition & 3 25 kV Breakers
Transformer addition and 2 25 kV breakers
One 25 kV breaker addition
Addition of 2-50MVA transformers at No. 26 Substation

2006
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$289,150 18.00
$372,823 41.00
$140,941 13.00
$1,287,488 25.55
$1,647,700 13.00
$3,531,000 14.00
$326,000
8.21
$1,963,870 23.50
$39,550 67.04
$518,373 40.00
$0 23.90
$4,371,000 60.30
$4,192,000 26.60
$3,822,000 13.60
$390,000 10.74
$600,000 11.70
$301,000 14.39
$5,727,000 14.80
$143,900 58.00
$4,925,000 40.00
$2,653,000 30.00
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$887,093 62.60
$4,365,000 29.10
25.20
$ 5,462,000
$2,387,000
9.20
$6,290,414
3.40
$0 230.00
$998,000 31.00
$5,738,000 41.40
$2,285,500 28.00
$415,000 26.54
$726,300 12.00
$2,477,670 16.00
$1,241,000 15.00
$354,000
2.00
$1,587,000 18.00
$4,750,000 47.60
$2,602,000 24.30
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$3,557,422 35.00

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$781,000

$2,009,000
$2,504,000

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$0

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$1,723,000

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$705,000

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$137,000
$2,154,450

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$0
$0

$1,740,000
$2,149,000
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$800,860

$600,000
$1,062,000
$184,000
$762,550

Sum: $94,395,287

$4,848,853 $69,703,389

$85,594,483

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3.666

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14.00
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14.08
18.00
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20.00
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8.00
0.10
13.95
20.00
14.43
14.43
10.00


September 23, 2009

TFO O&M Cost Causation Study Working Group Members
AESSO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for TFO O&M Cost Causation Study Working Group

The fourth meeting of the TFO O&M Cost Causation Study Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 10:00 AM to 12:00 Noon
- **Date:** Friday, September 25, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, pastries, and fruit

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. StatoilHydro Canada has already advised they are unable to participate in this meeting.

The agenda for the meeting is proposed to include the following items:

1. **Review agenda**

2. **Update on plan to finalize 2010 tariff application**
   - Application filing date delayed to late November
   - Documents on working group conclusions to be released for comments in September and October
   - General stakeholder consultation meeting in late October

3. **Review draft TFO O&M cost study (Arnie Reimer)**
   - Review draft study (posted on AESO website on September 14)
   - Discuss O&M cost causation methodology, results, and implementation

4. **Determination of O&M charge**
   - Discuss O&M charge determination methodology
   - Discuss application of O&M charge to all costs above maximum investment level
5 Follow-up required for next meeting  11:45 AM
• Discuss expected schedule for completion of study
• Summarize what tasks need to be completed before next meeting and who will complete them

6 Dates and times for next meeting(s)  11:55 AM
• Please bring your calendar information so the next meeting (if required) can accommodate everyone's schedule.

7 Adjourn  12:00 Noon

This agenda and all other printed information related to the TFO O&M Cost Causation Study Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2471 or david.michaud@aeso.ca.

Sincerely,
[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc:  David Michaud, Manager, Regulatory, AESO
     Arnie Reimer, TFO O&M Study, Consultant to AESO
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1. Executive Summary

This study was completed to better understand the causation of electric transmission operating and maintenance costs. The study was completed to address an AEUB Directions in Decision 2005-096 and Decision 2007-106 (Alberta Electric System Operator – 2006 and 2007 General Tariff Applications, respectively) regarding transmission system costs. This study is a follow up of past studies, the first of which was the Alberta Transmission System: Wires Only - Cost Causation Study that was an Appendix to the AESO 2006 General Tariff Application, and the Alberta Transmission System 2006 Transmission Cost Causation Update that was an Appendix to the 2007 General Tariff Application. Both of these previous reports studied the causation of capital costs of the electric transmission system and did not study the operating and maintenance costs. For the purpose of cost studies and rate design, operating and maintenance costs were assumed to follow in step with capital costs. Capital related costs of the electric transmission system comprise approximately 2/3 of the annual revenue requirement and non capital related costs comprise the remaining 1/3 of the annual revenue requirement.

Generally, the TFO O&M costs are considered all TFO costs that are not capital related costs. However, for some purposes, it is appropriate to separate non capital related costs into O&M and Administrative (or General and Administrative (G&A)).

This study was completed using traditional cost of service methods including: functionalization, classification and allocation of costs. As in previous transmission cost studies, the allocation of costs is not required because there is only one rate class.

The following table outlines the outcome of the previous cost study that considered capital costs, as well as the outcome of this study that considers non capital costs, and the weighting of the two to arrive at a cost basis for rate design.

<table>
<thead>
<tr>
<th>Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>34.0%</td>
<td>14.3%</td>
<td>17.6%</td>
<td>66.0%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>7.7%</td>
<td>3.0%</td>
<td>0.3%</td>
<td>11.0%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>41.7%</td>
<td>17.4%</td>
<td>40.9%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>11.3%</td>
<td>32.8%</td>
<td>17.7%</td>
<td>61.8%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>2.6%</td>
<td>8.6%</td>
<td>4.0%</td>
<td>15.2%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.1%</td>
<td>23.1%</td>
</tr>
<tr>
<td>Totals</td>
<td>13.8%</td>
<td>41.3%</td>
<td>44.8%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Weighted (33.8% Non Capital)</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>26.3%</td>
<td>20.6%</td>
<td>17.7%</td>
<td>64.5%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>6.0%</td>
<td>4.9%</td>
<td>1.6%</td>
<td>12.4%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>32.3%</td>
<td>25.5%</td>
<td>42.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
2. The Alberta Electric Transmission System

The Alberta Interconnected Electric System (AIES) is planned and operated by the Alberta Electric System Operator (AESO) in compliance with the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) standards and the WECC Reliability Management System.

The AIES consists of an electric transmission system connecting generation and loads in Alberta. The AIES is interconnected to BC through a 500 kV AC interconnection along with underlying 138 kV AC lines and is interconnected to Saskatchewan with an asynchronous DC link. The AIES includes transmission facilities with nominal voltages ranging from 69 kV to 500 kV AC. The AIES includes approximately 21,000 km of transmission lines and 500 substations and serves an annual peak load of 10,000 MW.

The cost of Alberta’s electric transmission system includes annual costs (2007) of:
- Wires $484 million
- Ancillary Services $266 million
- Losses $251 million
- Admin and Other $61 million
- Total $1,062 million

Prior to industry restructuring, the transmission system was part of the vertically integrated electric utility, and the transmission costs were generally considered one function, and were classified as demand related costs.

The Alberta Energy and Utilities Board (AEUB) directed the AESO to study transmission wires costs, and AESO filed the first Alberta Transmission System, Wires Only Cost Causation Study with its 2006 GTA. The AEUB generally approved of the concepts developed in the study and directed upgrades to the study in Decision 2005-096. In response to these directives, the AESO filed an Alberta Transmission System, 2006 Cost Causation Update with its 2007 GTA. The AEUB approved the update in Decision 2007-106 and directed further study in the area of operating and maintenance costs.

Decision 2007-106\(^2\) includes the following Direction:

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.

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1 Forecast costs from 2008 AESO Board Decision in Table 2-2 of AESO 2009 Rates Update Application, March 12, 2009.
This study is in response to the AEUB’s Direction and to provide a better understanding of electric transmission system operating and maintenance costs.

The purpose of this study is to refine the cost causation study to include O&M costs to refine cost causation, and the subsequent rate design for the Transmission Tariff.

Interveners in the 2007 GTA filed a request to review and vary the AEUB Decision 2007-106 in regards to customer contributions, specifically the prepaid O&M component of the customer contribution. The Alberta Utilities Commission (AUC) revised the method of calculating a customer contribution with respect to the prepaid O&M component in Decision 2009-105. Further, the AUC directed the following in Direction 3 in Decision 2009-105.

(3) The AESO shall file its analysis of the relationship between incremental O&M and interconnection capital costs, as originally directed by the Board in Decision 2005-096, by no later than the time of its next GTA.

This study also responds to the AUC Direction to study incremental O&M costs. The purpose of this study is to provide a better understanding of incremental O&M costs and provide a recommendation as to the validity of the existing 12% prepaid O&M charge.

### 2.1. Results of Previous Studies

The previous cost causation studies considered only capital related costs and the causation of these costs. Capital related costs consist of the majority of TFO costs and were used as the basis for all TFO costs. The previous studies assumed that O&M costs are incurred proportional to capital costs. This assumption was called into question during the 2006 and 2007 GTAs, and further study was directed to better understand the incurrence of O&M costs.

The following table summarizes the findings of previous studies in terms of the percent of revenue requirement functionalized as Bulk System, Local System and POD, and classified as Demand, Energy and Customer related.

<table>
<thead>
<tr>
<th>Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>34.0%</td>
<td>14.3%</td>
<td>17.6%</td>
<td>66.0%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>7.7%</td>
<td>3.0%</td>
<td>0.3%</td>
<td>11.0%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>41.7%</td>
<td>17.4%</td>
<td>40.9%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

---

3. TFO Cost Data

The AEUB Directions deal with study of operating and maintenance costs. To assist in the understanding of operating and maintenance costs, all of the TFO costs are first split into capital related costs and non capital related costs. The non capital costs are all of the costs that are not capital related and are used for the purpose of the cost of service and transmission tariff design. The non capital cost is broader than what is traditionally considered operating and maintenance cost. Non capital costs include general and administrative costs as well as operating and maintenance costs.

One purpose of this report is to study the causation of costs that are non capital related costs. The basic data for this study is compiled from the Transmission Facility Owner’s (TFO) General Tariff Application (GTA). Also, further requests were made for each TFO to provide additional information to assist in understanding the costs that comprise the GTA. Also, further meetings were conducted with each TFO to understand the cost information in the GTA and to understand the causation of these costs.

As in the previous studies, data was collected from the four largest TFO’s including AltaLink, ATCO Electric, ENMAX Power and EPCOR. In the interest of efficiency, the costs from the remaining TFO’s (Cities of Lethbridge and Red Deer, and TransAlta) are not considered. The costs from the three smallest TFO’s account for less than 3% of the TFO wires related costs.

3.1. Compilation of GTA Data

TFO cost data was compiled for the years 2006 through 2009 to consider both actual and forecast data where available. The cost data for 2008 was studied in depth to develop the cost causation study for non capital costs. Cost data was extracted from each TFO’s GTA, and the data is shown in Appendix A – TFO GTA Data. The summary of the cost data for the four largest TFO’s is shown in the following table.

Get rid of 2010, delete Management Fee, - Can we use ATCO Refiling???

<table>
<thead>
<tr>
<th>Sum of TFO Cost Data</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Portions</td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Fuel</td>
<td>8,394,000</td>
<td>8,700,000</td>
<td>8,200,000</td>
<td>9,300,000</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>135,242,780</td>
<td>142,001,488</td>
<td>160,113,555</td>
<td>184,770,788</td>
</tr>
<tr>
<td>Depreciation</td>
<td>116,809,507</td>
<td>121,396,515</td>
<td>132,647,804</td>
<td>144,135,060</td>
</tr>
<tr>
<td>Return on Rate Base</td>
<td>142,519,512</td>
<td>143,438,597</td>
<td>149,357,495</td>
<td>176,012,613</td>
</tr>
<tr>
<td>Revenue Offsets</td>
<td>-16,423,406</td>
<td>-14,288,952</td>
<td>-11,902,901</td>
<td>-9,638,948</td>
</tr>
<tr>
<td>Hearings, Self Ins, Other Taxes</td>
<td>18,871,016</td>
<td>16,838,329</td>
<td>19,030,459</td>
<td>21,173,543</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>429,778,524</td>
<td>438,302,638</td>
<td>471,554,738</td>
<td>542,395,201</td>
</tr>
</tbody>
</table>
4. Definition of Non Capital Related Costs

There is no universally accepted definition of what costs constitute operating and maintenance costs. The possible definitions of O&M costs range from as broad as all costs other than capital related costs to as narrow as the incremental cost of operating and maintaining electrical transmission facilities in use. The broad definition would include costs such as Human Resources that are not directly linked to operating and maintenance activities, while the narrow definition could exclude any overheads associated with operating and maintenance activities.

The AEUB Directions did not provide a definition of O&M costs, and in order to be of assistance to the process of rate design, the definition of O&M costs should be broad so as to include all not capital related costs. Therefore, for the purpose of rate design, O&M costs are defined to be all TFO costs that are not considered capital costs in the previous cost studies. Since all of these costs are based on the TFO revenue requirement, this study is based on embedded costs ($2008).

The AEUB Direction in Decision 2009-105 did not provide a definition of incremental O&M costs, and in order to be of assistance in the process of determining prepaid O&M costs associated with optional supply facilities, incremental O&M will be considered the direct cost of operating and maintaining electric transmission facilities as well as the overheads of planning and scheduling O&M activities. Therefore, general and administrative costs are excluded from the calculation of prepaid O&M costs. The cost calculation for this exercise is based on $2008– both RCN capital costs and operating and maintenance costs.

4.1. Capital Related Costs

The costs considered capital related costs include depreciation, return, management fee and income tax expense. The non capital related costs include fuel and operating costs. Revenue offsets are revenues that include both capital and operating related. Hearing, self insurance, other taxes and deferral accounts also include both capital and operating costs. The capital related costs of the electric transmission system comprise approximately 2/3 of the total revenue requirement.

The separation of capital costs from non capital costs is based on a review of all of the costs within the accounts. Each TFO has a Capitalization Policy that outlines which costs should be capitalized. Generally, when an activity will have long term value, the cost of that activity is capitalized. The capitalization policies of the four TFO’s studied are included in Appendix B. The cost of replacing and upgrading old equipment is known as capital maintenance and these costs are capitalized, and are not included in operating and maintenance costs.
4.2. Non Capital Related Costs

A transmission cost causation study for non capital related costs becomes more challenging because there is not always a direct correlation between the incurrence of an expense and the impact on the electric transmission system. The non capital related costs will be split into the following components for further review:

- Fuel
- Operating
- Revenue Offsets (some components)
- Hearings, Self Insurance, Other Taxes (some components)

4.2.1 Fuel

Transmission fuel costs are only incurred by one TFO. ATCO Electric incurs fuel costs for isolated generating stations and telecommunications sites that serve remote communities where it is less expensive to operate isolated generating stations instead of constructing transmission facilities to these communities and sites.

The cost of fuel for the electric transmission system is shown in the following table.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>8,394,000</td>
<td>8,700,000</td>
<td>8,200,000</td>
<td>9,300,000</td>
</tr>
</tbody>
</table>

The incurrence of this expense avoids the need to extend the Local System and POD.

4.2.2 Operating

The term operating costs is general and includes many of the non capital costs for each TFO. The following table shows the sum of the TFO’s operating costs.

<table>
<thead>
<tr>
<th>Operating</th>
<th>2006 Actual</th>
<th>2007 Actual</th>
<th>2008 Forecast</th>
<th>2009 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>135,242,780</td>
<td>142,001,488</td>
<td>160,113,555</td>
<td>184,770,788</td>
</tr>
</tbody>
</table>

These operating costs include all of the following:

- Operating costs
- Maintenance costs
- General and Administrative

Operating costs includes costs of operating a system control centre. Maintenance costs include the cost of maintaining electric transmission lines and substations as well as the overheads of planning and scheduling this maintenance.
The General and Administrative costs include costs that are not directly related to the operations and maintenance of the electric transmission system. Examples of these costs include costs associated with office and staff expenses, Community Relations and building services.

4.2.3 Revenue Offsets

Revenue offsets include an assortment of revenues to the TFO’s that are not part of the TFO’s core business. For example, the TFO’s charge for line moves when a customer requests that a line be moved. The TFO incurs a cost to move the line and the TFO levies a charge to the customer to recover this cost.

Revenue offsets include revenues for line moves, joint use (shared use of poles with other utilities), shared services from affiliates and other services to outside parties. The total revenue offsets from the four largest TFO’s are shown in the table below.

<table>
<thead>
<tr>
<th>Revenue Offsets</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Total</td>
<td>-16,423,406</td>
<td>-14,288,952</td>
<td>-11,902,901</td>
<td>-9,638,948</td>
</tr>
</tbody>
</table>

Where revenue offsets occur as the result of operating and maintenance costs, the revenue offsets are treated in the same manner as the operating costs with respect to functionalization and classification of these costs.

4.2.4 Hearings, Self Insurance, Other Taxes

The cost of hearings, self insurance and other taxes are considered non capital related costs. The Taxes other than income tax are associated with electric transmission facilities and can be functionalized while the cost of hearings and self insurance do not have a direct correlation to electric transmission facilities and will be treated as general and administrative costs.

<table>
<thead>
<tr>
<th>Hearings, Self Ins, Other Taxes</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deferral and Reserve Accounts</td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Total</td>
<td>18,871,016</td>
<td>16,838,329</td>
<td>19,030,459</td>
<td>21,173,543</td>
</tr>
</tbody>
</table>
5. Cost of Service (Non Capital Costs)

The traditional cost of service methods have been based on vertically integrated electric utility companies. The traditional cost of service studies first functionalize costs, then classify costs and finally allocate costs to the appropriate rate class.

Stand alone cost of service studies on the electric transmission system are not common and transmission costs are generally considered as one function, and are generally classified as demand related.

Electric transmission systems are capital intensive and the majority of costs of owning, operating and maintaining an electric transmission system are considered capital costs. As shown in the following table derived from the TFO’s GTAs, the operating costs (Fuel and Operating, with the remainder of costs assumed capital related costs) are about 1/3 of the annual TFO revenue requirement.

<table>
<thead>
<tr>
<th>(Fuel &amp; Operating)/Rev Req</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
<td></td>
</tr>
<tr>
<td>AltaLink</td>
<td>26.3%</td>
<td>25.1%</td>
<td>25.6%</td>
<td>26.8%</td>
<td>25.9%</td>
</tr>
<tr>
<td>ATCO Electric</td>
<td>35.8%</td>
<td>38.3%</td>
<td>41.8%</td>
<td>41.7%</td>
<td>39.4%</td>
</tr>
<tr>
<td>ENMAX</td>
<td>53.4%</td>
<td>57.5%</td>
<td>57.6%</td>
<td>56.8%</td>
<td>56.3%</td>
</tr>
<tr>
<td>EPCOR</td>
<td>41.2%</td>
<td>48.1%</td>
<td>43.2%</td>
<td>40.1%</td>
<td>43.2%</td>
</tr>
<tr>
<td>Total</td>
<td>33.4%</td>
<td>34.4%</td>
<td>35.7%</td>
<td>35.8%</td>
<td>34.8%</td>
</tr>
</tbody>
</table>

A review of the cost shown in Section 3.1 indicates that revenue offsets include revenue that offset both capital costs and operating costs. The Revenue Offsets were reviewed to assess which costs were capital related and which were associated with operating costs. The revenues associated with operating costs include revenues from affiliates, and from other parties such as movers requesting that lines be raised. When adjusting for revenue offsets, the non capital costs as a percentage of revenue requirement are as shown in the following table.

<table>
<thead>
<tr>
<th>(Fuel,Op &amp; Offset)/Rev Req</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
<td></td>
</tr>
<tr>
<td>AltaLink</td>
<td>25.9%</td>
<td>24.6%</td>
<td>25.1%</td>
<td>26.4%</td>
<td>25.5%</td>
</tr>
<tr>
<td>ATCO Electric</td>
<td>34.1%</td>
<td>36.6%</td>
<td>41.0%</td>
<td>41.0%</td>
<td>38.2%</td>
</tr>
<tr>
<td>ENMAX</td>
<td>53.4%</td>
<td>57.5%</td>
<td>57.6%</td>
<td>56.8%</td>
<td>56.3%</td>
</tr>
<tr>
<td>EPCOR</td>
<td>35.8%</td>
<td>41.5%</td>
<td>41.9%</td>
<td>39.1%</td>
<td>39.6%</td>
</tr>
<tr>
<td>Total</td>
<td>32.1%</td>
<td>33.0%</td>
<td>35.0%</td>
<td>35.2%</td>
<td>33.8%</td>
</tr>
</tbody>
</table>

The portions of the costs that are non capital related fluctuate from year to year. To minimize the annual fluctuations, the four year average of 33.8% will be used for weighting of non capital related costs.
5.1. Functionalization

The operating and maintenance costs are sub functionalized into one of the three sub functions:

- Bulk System
- Local System
- POD (Point of Delivery)

For the purpose of this report, the Bulk Transmission System is the 240 kV and 500 kV transmission facilities, including substations that transform voltage to a lower transmission voltage (i.e. 240/138 kV substation). The Local Transmission System consists of the 138/144 kV and 69/72 kV transmission facilities, while the POD includes radial transmission lines and point of delivery substations.

The Wires Cost Causation Report used three methods of functionalizing electric transmission facilities: voltage level, economics and MW-km. All three methods had advantages and disadvantages and all three produced similar results. Since there was no method that was clearly superior to the others, the average of the three methods was used. The voltage level method is easy to understand and correlate to electric transmission facilities. Voltage levels are used for the study of O&M costs for ease of understanding and to simplify the study.

Brushing

Vegetation management occurs in various cycles from grass cutting twice per year around substations and telecommunications sites to every 10 years for base mowing. The difference between brushing under steel towers versus wood poles is the clearance required between the vegetation and the line.

Vegetation management includes trimming, mowing, spraying and slashing and removal and all of these activities are priced in terms of area cleared. The amount spent on brushing varies from year to year, and the actual activities and location of work also vary each year. Therefore the actual cost for 2008 was used and was functionalized on the basis of line length and width of brushing activities. This method removes anomalies associated with studying one year of a multiple year cycle for brushing. For example, line brushing for AltaLink was functionalized as follows:

<table>
<thead>
<tr>
<th>Voltage (kV)</th>
<th>Line Len (kM)</th>
<th>Width (m)</th>
<th>Area (1000 m²)</th>
<th>Total by Function</th>
<th>Proportion by Function</th>
<th>Functionalization</th>
</tr>
</thead>
<tbody>
<tr>
<td>69</td>
<td>847</td>
<td>15</td>
<td>12,707</td>
<td>138,877</td>
<td>40.6%</td>
<td>Local</td>
</tr>
<tr>
<td>138</td>
<td>6,309</td>
<td>20</td>
<td>126,170</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>240</td>
<td>4,643</td>
<td>40</td>
<td>185,737</td>
<td>203,282</td>
<td>59.4%</td>
<td>Bulk</td>
</tr>
<tr>
<td>500</td>
<td>319</td>
<td>55</td>
<td>17,545</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>12,118</td>
<td></td>
<td>342,159</td>
<td>342,159</td>
<td>100.0%</td>
<td></td>
</tr>
</tbody>
</table>
Line vegetation management was all functionalized to bulk and local systems as shown above and other vegetation management was split between lines and POD’s.

The functionalization of AltaLink Brushing costs as summarized as follows:

<table>
<thead>
<tr>
<th>Brushing (AltaLink)</th>
<th>2006 Actual</th>
<th>2007 Actual</th>
<th>2008 Man Update</th>
<th>2009 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk</td>
<td>1,989,499</td>
<td>2,455,111</td>
<td>3,004,844</td>
<td>2,558,859</td>
</tr>
<tr>
<td>Local</td>
<td>1,359,172</td>
<td>1,677,266</td>
<td>2,052,829</td>
<td>1,748,144</td>
</tr>
<tr>
<td>POD</td>
<td>150,000</td>
<td>200,000</td>
<td>150,000</td>
<td>450,000</td>
</tr>
<tr>
<td>Total VM</td>
<td>3,498,671</td>
<td>4,332,376</td>
<td>5,207,673</td>
<td>4,757,002</td>
</tr>
</tbody>
</table>

Annual Structure Payments

Annual structure payments were functionalized on the basis of line length and a summary of the results are shown in the table below.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk</td>
<td>657,611</td>
<td>856,177</td>
<td>1,215,685</td>
<td>2,293,240</td>
</tr>
<tr>
<td>Local</td>
<td>948,249</td>
<td>1,234,573</td>
<td>1,752,969</td>
<td>3,306,760</td>
</tr>
<tr>
<td>POD</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Sub Total</td>
<td>1,605,861</td>
<td>2,090,751</td>
<td>2,968,654</td>
<td>5,600,000</td>
</tr>
</tbody>
</table>

Fuel

Fuel costs are associated with remote communities that are not interconnected to the Alberta Interconnected Electric System (AIES). Instead of interconnecting to the larger grid, it is less expensive to provide service with a local generator, typically diesel fired. This fuel cost is considered transmission, because in its absence, the transmission system would have to be expanded to provide service, incurring greater electric transmission costs. Since all of these communities are small, any transmission system that would be built to interconnect would be a local system and POD, and therefore no fuel costs are functionalized as Bulk System. The fuel cost was functionalized as POD and Local System on the basis of the overall system capital where 40.9% of total property is POD, and 17.4% is Local System. The ATCO fuel cost functionalization is shown in the summary table below.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Local</td>
<td>2,502,409</td>
<td>2,593,633</td>
<td>2,444,574</td>
<td>2,772,504</td>
</tr>
<tr>
<td>POD</td>
<td>5,891,591</td>
<td>6,106,367</td>
<td>5,755,426</td>
<td>6,527,496</td>
</tr>
</tbody>
</table>

Operations – Net Salary

Salaries are a large item in the Operating account. Salaries are functionalized on the basis of the staff complement. Field personnel are generally in departments that work on either substations or lines and thus the functionalization follows the work of the staff.
Some office personnel also work on either substations or lines, and the functionalization also aligns with the work of the staff. The System Control Centre is unique in that the personnel are physically located in a centralized control centre, but they operate switches in the field. For the purpose of the System Control Centre, the number of switches in the field was used as the basis of functionalization.

The following example is an extract of the AltaLink Net Salary costs and similar analysis was done for other TFOs:

<table>
<thead>
<tr>
<th>Net Salaries and Wages</th>
<th>2006 Actual</th>
<th>2007 Actual</th>
<th>2008 Man Update</th>
<th>2009 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk</td>
<td>3,241,881</td>
<td>3,651,985</td>
<td>4,213,193</td>
<td>4,920,599</td>
</tr>
<tr>
<td>Local</td>
<td>6,258,913</td>
<td>6,457,934</td>
<td>7,376,223</td>
<td>8,647,636</td>
</tr>
<tr>
<td>POD</td>
<td>12,038,140</td>
<td>11,854,069</td>
<td>13,663,632</td>
<td>16,071,926</td>
</tr>
<tr>
<td>Total</td>
<td>21,538,934</td>
<td>21,963,987</td>
<td>25,253,048</td>
<td>29,640,161</td>
</tr>
</tbody>
</table>

Summary

With all of the parts combined, the functionalized cost by TFO is shown in the following table. The table shows the 2008 costs that were analyzed and also other years where the same methodology was applied. The last two columns shows the proportions for 2008 and for the 4 year average.

<table>
<thead>
<tr>
<th>AltaLink</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>Total</th>
<th>2008 Portion</th>
<th>4 Year Ave Portion</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bulk</td>
<td>11,692,837</td>
<td>12,387,112</td>
<td>13,471,383</td>
<td>16,172,638</td>
<td>53,723,970</td>
<td>23.6%</td>
</tr>
<tr>
<td></td>
<td>Local</td>
<td>16,516,616</td>
<td>16,649,548</td>
<td>17,731,936</td>
<td>22,379,803</td>
<td>73,277,903</td>
<td>31.1%</td>
</tr>
<tr>
<td></td>
<td>POD</td>
<td>23,984,293</td>
<td>24,232,925</td>
<td>25,822,534</td>
<td>31,134,827</td>
<td>105,174,580</td>
<td>45.3%</td>
</tr>
<tr>
<td>ENMAX</td>
<td>Bulk</td>
<td>4,517,192</td>
<td>4,740,713</td>
<td>5,685,479</td>
<td>6,740,709</td>
<td>21,684,092</td>
<td>9.8%</td>
</tr>
<tr>
<td></td>
<td>Local</td>
<td>24,499,429</td>
<td>26,166,102</td>
<td>29,250,985</td>
<td>34,118,085</td>
<td>114,034,601</td>
<td>50.5%</td>
</tr>
<tr>
<td></td>
<td>POD</td>
<td>19,715,379</td>
<td>20,793,185</td>
<td>22,963,536</td>
<td>26,141,206</td>
<td>89,613,306</td>
<td>39.7%</td>
</tr>
<tr>
<td>EPCCOR</td>
<td>Bulk</td>
<td>257,654</td>
<td>284,806</td>
<td>297,984</td>
<td>313,499</td>
<td>1,153,943</td>
<td>1.6%</td>
</tr>
<tr>
<td></td>
<td>Local</td>
<td>7,345,746</td>
<td>8,119,832</td>
<td>8,495,551</td>
<td>8,937,869</td>
<td>32,898,999</td>
<td>44.9%</td>
</tr>
<tr>
<td></td>
<td>POD</td>
<td>8,760,251</td>
<td>9,683,396</td>
<td>10,131,463</td>
<td>10,658,955</td>
<td>39,234,065</td>
<td>53.5%</td>
</tr>
<tr>
<td>Total</td>
<td>Bulk</td>
<td>18,126,306</td>
<td>19,098,193</td>
<td>21,229,510</td>
<td>25,114,138</td>
<td>83,568,148</td>
<td>13.8%</td>
</tr>
<tr>
<td></td>
<td>Local</td>
<td>54,532,117</td>
<td>56,930,491</td>
<td>63,384,367</td>
<td>74,357,904</td>
<td>249,204,879</td>
<td>41.3%</td>
</tr>
<tr>
<td></td>
<td>POD</td>
<td>61,582,349</td>
<td>63,980,101</td>
<td>68,678,184</td>
<td>78,315,101</td>
<td>272,555,735</td>
<td>44.8%</td>
</tr>
</tbody>
</table>

5.2. Classification

Classification of electric transmission non capital costs is a challenge. Capital costs always have an asset associated with the cost, and the asset has a rating or specification
that provides information on the classification of the cost. Non capital costs do not have any ratings or specifications associated with them to assist in the classification.

The fuel cost is an item that is not normally associated with transmission lines, however, there are a number of remote communities that are served with isolated generators rather than being interconnected to the AIES. The cost of isolated generation is less than the cost of building transmission lines and a POD to supply remote communities, and therefore the cost of the isolated generation replaces the cost of the transmission system and POD. The fuel cost is incurred in order to save transmission infrastructure costs. The fuel cost is a variable cost that is related to the energy consumption in the communities served by remote generators. Therefore, fuel costs are classified as energy related.

Other non capital costs and their associated activities occur for the purpose of ensuring the existing transmission systems continues to perform reliably and adequately in accordance with the design of the system.

Activities such as vegetation management occur in order to avoid contact between vegetation and transmission lines. The activities normally occur on a time based schedule and these activities are independent of the amount of demand on the transmission line, the amount of energy flowing through the line, or the number of POD’s connected downstream of the line.

Activities such as breaker and LTC maintenance may occur on a time based schedule, or number of operations (usage based schedule). These activities are also independent of the amount of demand on the transmission line, the amount of energy flowing through the line, or the number of POD’s connected downstream of the line.

Operational and maintenance activities may be scheduled by methods other than time or usage based such as reliability based maintenance or may be initiated by predictive maintenance practices and monitoring.

No operational or maintenance activities were identified where costs are incurred in relationship to demand, energy or the number of customers. Since all of the costs that are incurred are done so to maintain the system to service its design function, the capital cost classification is used for non capital related costs other than fuel.

### 5.3. Allocation

The last step of a traditional cost of service study is not required in this case because there is only one rate class that is responsible to pay for the costs of the transmission system and that is the load customers through the DTS Rate of the AESO Transmission Tariff. The step of allocation is not required for the purpose of the transmission tariff rate design.
5.4. Results

When the revenue requirements from the four TFO’s are functionalized and classified as described earlier in Section 5, the result is shown in the following table:

<table>
<thead>
<tr>
<th>TFO Non Capital Costs (2008)</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>17,302,088</td>
<td>50,274,957</td>
<td>27,119,691</td>
<td>94,696,736</td>
</tr>
<tr>
<td>Energy Related</td>
<td>3,927,422</td>
<td>13,109,410</td>
<td>6,195,809</td>
<td>23,232,641</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0</td>
<td>0</td>
<td>35,362,685</td>
<td>35,362,685</td>
</tr>
<tr>
<td>Totals</td>
<td>21,229,510</td>
<td>63,384,367</td>
<td>68,678,184</td>
<td>153,292,061</td>
</tr>
</tbody>
</table>

The proportions of these costs are shown in the following table:

<table>
<thead>
<tr>
<th>Non Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>11.3%</td>
<td>32.8%</td>
<td>17.7%</td>
<td>61.8%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>2.6%</td>
<td>8.6%</td>
<td>4.0%</td>
<td>15.2%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.1%</td>
<td>23.1%</td>
</tr>
<tr>
<td>Totals</td>
<td>13.8%</td>
<td>41.3%</td>
<td>44.8%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

The capital related cost proportions from the earlier studies is shown below:

<table>
<thead>
<tr>
<th>Capital Related Costs</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>34.0%</td>
<td>14.3%</td>
<td>17.6%</td>
<td>66.0%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>7.7%</td>
<td>3.0%</td>
<td>0.3%</td>
<td>11.0%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>41.7%</td>
<td>17.4%</td>
<td>40.9%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Based on the analysis, 35% of the revenue requirement is non capital related and the two tables above are averaged together on a weighted basis where 65% of the weight is placed on the capital cost, and the remaining 35% of the weight is place on the non capital cost as follows:

<table>
<thead>
<tr>
<th>Weighted (33.8% Non Capital)</th>
<th>Bulk System</th>
<th>Local System</th>
<th>POD</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Related</td>
<td>26.3%</td>
<td>20.6%</td>
<td>17.7%</td>
<td>64.5%</td>
</tr>
<tr>
<td>Energy Related</td>
<td>6.0%</td>
<td>4.9%</td>
<td>1.6%</td>
<td>12.4%</td>
</tr>
<tr>
<td>Customer (POD)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>23.0%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Totals</td>
<td>32.3%</td>
<td>25.5%</td>
<td>42.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
6. Prepaid O&M Charges

New customers to the electric transmission system who require optional facilities (facilities in excess of those provided for in standard service) are levied a charge to ensure existing customers are not required to subsidize the new customers who have a requirement for optional facilities. Optional facilities are typically redundant transformers, redundant lines of supply or extra switchgear that provide additional reliability and operational flexibility.

The charge levied for optional facilities includes the capital cost of installing the equipment plus an additional charge referred to as Prepaid O&M, to cover the future additional costs of operating and maintaining these optional facilities.

The costs associated with optional facilities are by nature variable. The costs will be incurred if the optional facilities are in place, and will not occur if the facilities are not in place. As such, if the customer and the optional facilities cease to exist, the variable costs will also cease.

There are several issues that must be determined in order to determine an appropriate level and structure of the Prepaid O&M charge. These issues require the determination of:

- Costs that apply
- Applicable time frame to calculate costs
- The nature of the costs and the associated structure of the charge

6.1. Applicable Costs

The principle in determining applicable costs is that other customers should not subsidize the new customer who requires optional facilities. The scope of this charge could be as large as all non capital costs described earlier in this report, and could be as narrow as incremental costs identified with the optional facilities.

The broad definition of applicable costs includes all non capital related costs. On an embedded basis, and on the assumption that all non capital costs are correlated to capital costs, it would be reasonable to expect a new customer to pay the total non capital related cost associated with optional facilities.

A narrower definition of applicable costs is those costs that can be demonstrated as incremental as the result of the service of optional facilities. This narrower definition would exclude indirect non capital costs such as the cost of Hearings, and operating costs such as IT and Human Resources. The narrower definition of costs would include all costs related to the operating and maintenance of these facilities including direct cost of operations, maintenance, overheads associated with planning and scheduling of maintenance, and incremental costs such as taxes other than income tax.
6.2. Time Frame

The time frame over which additional costs are applicable must be determined. Electric transmission facilities have long service lives that generally average 30 years of life or longer. This lengthy service life is often longer than the planning horizon of electric utilities or other businesses. The electric transmission system also changes over time and some facilities that may initially be optional will be standard facilities at some point through changes in the electric transmission system.

Business does not normally enter contracts that exceed 20 years because of the uncertainty of business over that period of time. The longest contract term for system access service with the AESO is similarly 20 years.

Given the potential changes in the electric transmission system and the difficulty in planning for and contracting for services in excess of 20 years, a maximum of 20 years should be considered the applicable time for incremental costs associated with optional facilities.

6.3. Nature of Costs

The incremental costs associated with optional facilities are not fixed costs in the long term. If a customer requires redundant facilities and contracts for those facilities, but ceases to operate in the future, the optional facilities can be salvaged and future O&M costs will go to zero. If these facilities have value for other customers in the future, the facilities can be kept in place and other customers that benefit from these facilities should pay for their use.

The existing nature of the Prepaid O&M charge (one time charge at the start of service) does not match the incurrence of costs which will occur periodically. If a customer ceases to require optional facilities and the facilities are salvaged, then the Prepaid O&M portion of the CIAC paid by the customer (less amortization of the CIAC over the elapsed time) should be refunded to the customer.

Given the variable nature of these costs, another approach to recover these costs could be an annual charge applicable for the O&M associated with optional facilities. This annual charge would match costs, and could be cancelled if the customer ceases to exist or incremental costs of optional facilities no longer exist.

6.4. Determination of Costs

Further analysis is being conducted to complete the remainder of this report. The current challenge is to determine the RCN of the existing transmission system to try to find a correlation between RCN and Non Capital costs, or O&M costs.
7. Summary

Parking Lot – O&M costs do not necessarily change with the age of facilities… Capital maintenance costs do increase with the age of facilities, but this is a capital cost, not one of interest in the O&M study.
8. Appendix A – TFO GTA Revenue Requirement

### TFO Cost Data
**All Values in $**

<table>
<thead>
<tr>
<th></th>
<th>AltaLink</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2006</td>
<td>2007</td>
<td>2008</td>
<td>2009</td>
</tr>
<tr>
<td></td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Fuel</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>49,807,854</td>
<td>50,806,899</td>
<td>54,891,958</td>
<td>65,971,924</td>
</tr>
<tr>
<td>Depreciation</td>
<td>64,826,350</td>
<td>68,519,547</td>
<td>74,462,618</td>
<td>78,041,499</td>
</tr>
<tr>
<td>Return on Rate Base</td>
<td>56,357,854</td>
<td>63,523,052</td>
<td>64,422,450</td>
<td>74,739,024</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>12,356,943</td>
<td>11,709,535</td>
<td>10,437,500</td>
<td>13,000,633</td>
</tr>
<tr>
<td>Revenue Offsets</td>
<td>-9,862,478</td>
<td>-9,534,866</td>
<td>-8,655,559</td>
<td>-6,271,699</td>
</tr>
<tr>
<td>Hearings, Self Ins, Other Taxes</td>
<td>15,832,979</td>
<td>17,743,162</td>
<td>18,886,693</td>
<td>21,029,776</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>189,319,502</td>
<td>202,767,328</td>
<td>214,445,660</td>
<td>246,511,157</td>
</tr>
</tbody>
</table>

### ATCO
**All Values in $**

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Fuel</td>
<td>8,394,000</td>
<td>8,700,000</td>
<td>8,200,000</td>
<td>9,300,000</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>51,671,900</td>
<td>55,800,000</td>
<td>66,500,000</td>
<td>77,100,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>38,600,000</td>
<td>38,500,000</td>
<td>41,600,000</td>
<td>47,000,000</td>
</tr>
<tr>
<td>Return on Rate Base</td>
<td>61,200,000</td>
<td>60,800,000</td>
<td>61,230,000</td>
<td>72,518,378</td>
</tr>
<tr>
<td>Income Tax Expense</td>
<td>12,008,171</td>
<td>8,507,126</td>
<td>3,670,826</td>
<td>3,641,514</td>
</tr>
<tr>
<td>Revenue Offsets</td>
<td>-4,022,000</td>
<td>-4,100,000</td>
<td>-2,600,000</td>
<td>-2,600,000</td>
</tr>
<tr>
<td>Deferral &amp; Reserve Accounts</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>167,852,071</td>
<td>168,207,126</td>
<td>178,600,826</td>
<td>206,959,891</td>
</tr>
</tbody>
</table>

### ENMAX
**All Values in $**

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Forecast</td>
<td>Forecast</td>
<td>Forecast</td>
</tr>
<tr>
<td>Fuel</td>
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<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>16,811,652</td>
<td>18,443,422</td>
<td>19,280,387</td>
<td>20,509,312</td>
</tr>
<tr>
<td>Depreciation</td>
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<td>6,538,419</td>
<td>7,088,576</td>
<td>7,969,376</td>
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<td>Return on Equity</td>
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<td>Interest Expense</td>
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<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Revenue Offsets</td>
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<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hearings, Self Ins, Other Taxes</td>
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<td>0</td>
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<td>32,096,378</td>
<td>33,462,446</td>
<td>36,080,238</td>
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## TFO Cost Data

All Values in $

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
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<td>Fuel</td>
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<td>0</td>
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<tr>
<td>Operating Costs</td>
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<td>Revenue Offsets</td>
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<td>45,045,806</td>
<td>52,843,915</td>
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</table>

## Sum of TFO Cost Data

All Values in $

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
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<tr>
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<td>132,647,804</td>
<td>144,135,060</td>
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<td>Return on Rate Base</td>
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<td>176,012,613</td>
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<tr>
<td>Revenue Offsets</td>
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<td>-14,288,952</td>
<td>-11,902,901</td>
<td>-9,638,948</td>
</tr>
<tr>
<td>Hearings, Self Ins, Other Taxes</td>
<td>18,871,016</td>
<td>16,838,329</td>
<td>19,030,459</td>
<td>21,173,543</td>
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<td>Revenue Requirement</td>
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<td>438,302,638</td>
<td>471,554,738</td>
<td>542,395,201</td>
</tr>
</tbody>
</table>

Note: The sum of TFO cost data includes only AltaLink, ATCO, ENMAX and EPCOR.
9. Appendix B – Capitalization Policies

Have EPCOR, AltaLink and ATCO
10. Background.

Decision 2007-106

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.

Produce a report for the AESO that will be part of the next AESO GTA outlining operating and maintenance costs of electric transmission systems. The report will address Directive #6 in the EUB Decision 2007-106. The report will study and provide recommendations for the functionalization and classification of O&M costs for use in AESO’s transmission tariff design 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.

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 O&M 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.
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.
June 17, 2009

TFO O&M Cost Causation Study Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for TFO O&M Cost Causation Study Working Group

The second meeting of the TFO O&M Cost Causation Study Working Group for the AESO’s 2010 tariff application is scheduled as follows:

<table>
<thead>
<tr>
<th>Time</th>
<th>1:00 to 3:00 PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date</td>
<td>Thursday, June 18, 2009</td>
</tr>
<tr>
<td>Location</td>
<td>Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary</td>
</tr>
<tr>
<td>Refreshments</td>
<td>Coffee, juice, and snacks</td>
</tr>
</tbody>
</table>

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Review agenda**
   - 1:00 PM

2. **Review notes from last meeting**
   - 1:05 PM
   - See enclosed document

3. **Update on TFO O&M cost causation study**
   - 1:10 PM
   - Review revised study scope (enclosed)
   - Discuss further details of data gathering including questions to be used in interviews with the TFOs
   - Discuss preliminary results on functionalization of costs between bulk system, local system, and point of delivery (which indicates less-than-average O&M should be attributed to the bulk system and more-than-average to the local system)
   - Discuss expected schedule for completion of study
   - What items should be taken to stakeholders for broader consultation?

4. **Incorporation of study results into rate design**
   - 2:00 PM
   - The AESO expects to simply add functionalized and classified O&M costs to functionalized and classified capital costs, to provide functionalized and classified total costs
   - Are there other considerations that should be accounted for?
Determination of O&M charge  2:30 PM
• What approaches could be used to determine the percentage O&M charge to be used in the calculation of customer contribution?

Follow-up required for next meeting  2:45 PM
• Summarize what tasks need to be completed before next meeting and who will complete them

Dates and times for next meeting(s)  2:55 PM

Adjourn  3:00 PM

This agenda and all other printed information related to the TFO O&M Cost Causation Study Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff » Current Consultations » 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2471 or david.michaud@aeso.ca.

Sincerely,
[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: David Michaud, Manager, Regulatory, AESO
Arnie Reimer, TFO O&M Study, Consultant to AESO
TFO O&M Cost Causation Study Working Group  
Meeting Notes for May 25, 2009

The following notes summarize items on which participants had discussion of substance. If an agenda item was simply reviewed and acknowledged, it is not included in these notes.

1 Participants
- AltaLink: James Yeo (representing AltaLink TFO)
- ENMAX: Penny Haldane (representing ENMAX Power TFO and DFO)
- EPCOR: Stan Yee (representing EPCOR TFO and DFO, by conference call)
- AESO: John Martin and David Michaud
- Consultant to AESO: Arnie Reimer

2 Action Items
(a) AESO: Revise scope of study to reflect discussion in items 3 and 5.

3 Next Meeting
(a) 1:00-3:00 PM on Thursday, June 18, 2009.

4 TFO O&M Cost Causation Study
(a) For previous study filed with 2006 tariff application, TFOs provided extensive confidential facilities data by line and substation. This O&M study looks like it won't require as extensive data nor confidential data. If necessary, Arnie will sign confidentiality agreements with the TFOs as was done for the prior study.
(b) The study will include the four largest TFOs in the province: AltaLink, ATCO Electric, ENMAX Power, and EPCOR. At this time it doesn’t appear there will be significant extra costs for the TFOs to provide the necessary data, but if so payment of those TFO costs would need to be addressed.
(c) The cost-effectiveness of the study should be assessed. In its 2007 GTA Refiling, the AESO estimated the study would incur on the order of $100,000 in AESO and consultant costs. This estimate still seems appropriate, and the value of the study seems worth that expenditure.

5 Definition of TFO O&M
(a) TFO O&M could be defined very broadly as all TFO costs except capital-related costs, or very narrowly as costs of those departments directly involved in operation and maintenance of transmission facilities in the field. The broader definition is easiest to deal with and generally aligns with the rate structure. Use of a narrower definition would leave the issue of how to deal with the balance of non-capital-related costs. Participants support the adoption of a broad definition of TFO O&M for this study.
(b) TFO costs identified as capital maintenance will not be considered as O&M for the study.

6 Years of Data for Study
(a) Arnie will use five years of data for the study, from 2005 to 2009 inclusive. The original study in 2005 was based on facilities data for 2003 and 2004. The different data years should not be a problem as the transmission system has not changed extensively over those years.
(b) Although the study will be based on five years of data, the study will examine O&M over the life of the transmission facilities.

(c) Information for the study will rely in large part on interviews with TFO employees, and interpretation of the information by Arnie. The study will generally be less data-intensive than the original cost causation study.

7 Scope of Study
(a) The draft study scope suggested examining the type of maintenance — whether predictive, preventive, or reactive. After discussion, participants concluded those distinctions are not relevant to the outcome of the study and should be removed from the study scope.

(b) In discussion after the meeting, Arnie noted the draft study scope did not mention reviewing the level of the 12% O&M charge. The examination of TFO O&M should lend itself to addressing that issue, as well. The direction on the 12% O&M charge has been included in the revised study scope enclosed with these notes.

(c) The study should include a summary of the questions asked during the TFO interviews.

8 Expected Outcome of Study
(a) The 2006 Transmission Cost Causation Update filed with the AESO’s 2007 GTA included the following functionalization and classification of all TFO costs (both capital and O&M):

<table>
<thead>
<tr>
<th>Classification</th>
<th>Total</th>
<th>Demand ($/MW)</th>
<th>Usage ($/MWh)</th>
<th>Customer ($/month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>41.7%</td>
<td>34.2%</td>
<td>7.5%</td>
<td>-</td>
</tr>
<tr>
<td>Local System</td>
<td>17.4%</td>
<td>14.3%</td>
<td>3.1%</td>
<td>-</td>
</tr>
<tr>
<td>POD</td>
<td>40.9%</td>
<td>35.0%</td>
<td>-</td>
<td>5.9%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>83.5%</td>
<td>10.6%</td>
<td>5.9%</td>
</tr>
</tbody>
</table>

(b) The TFO O&M study is expected to result in a similar table that functionalizes and classifies O&M costs. The table above would then be used for the approximately 67% to 75% of TFO costs that are capital-related, while the O&M study table would be used for the balance of approximately 25% to 33% of TFO costs that are considered O&M-related.

(c) For consistency between both studies, high-voltage switchgear in substations will continue to be functionalized as POD costs, as in the original study.

(d) The functionalization of O&M costs will primarily be based on the TFO interviews. So far, the only item that may be problematic appears to be telecontrol equipment.

9 Initial Indications
(a) O&M appears to be incurred to maintain or improve reliability of transmission facilities, and reliability-related costs are generally classified as demand-related costs. No energy-related costs have yet been suggested for O&M activities.

10 Enclosure
(a) Revised TFO O&M Cost Causation Study Scope
1 Study Purpose

The study will allow the AESO to respond to the following AUC directions:

**Direction 4D in Decision 2005-096 (page 23)**
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.

**Direction 20A in Decision 2005-096 (page 69)**
While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application.

**Direction 2 in Decision 2007-106 (page 25)**
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.

**Direction 18 in Decision 2007-106 (page 106)**
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.

2 Study Summary

Produce a report for the AESO that will be part of the next AESO GTA outlining operating and maintenance costs of electric transmission systems. The report will address the directions listed
above from Decisions 2005-096 and 2007-106. The report will study and provide recommendations for the functionalization and classification of O&M costs for use in AESO’s transmission tariff design.

3 Study Scope

1. Identify Total Revenue Requirement for four largest TFOs in Alberta for 2 or 3 historical years, by year:
   a. Breakdown of costs into capital and O&M
   b. Breakdown of O&M costs

2. Study O&M costs:
   a. Over the service life of the facilities
   b. By the type of facilities
      i. Transmission lines
      ii. Substations and switching apparatus
      iii. Transformers
      iv. Protection and Controls
      v. Telecommunication

3. Develop relationship of:
   a. O&M costs in relation to capital costs
   b. O&M costs in relation to transmission functions
      i. Bulk
      ii. Local
      iii. POD
   c. O&M costs in relation to:
      i. Demand related
      ii. Energy related
      iii. Fixed

4 Schedule and Cost

The time to complete the study is estimated at six months. Within this period, there will be requests to TFOs for cost information, and time will be required for response. Following the compilation of data, stakeholder information sessions will be held to update stakeholders as to progress and direction as well as preliminary results. Stakeholders will be afforded an opportunity to provide input.
May 25, 2009

TFO O&M Cost Causation Study Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for TFO O&M Cost Causation Study Working Group

The first meeting of the TFO O&M Cost Causation Study Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 1:00 to 3:00 PM
- **Date:** Monday, May 25, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee and juice

This working group includes the following members:

- AltaLink: James Yeo
- ENMAX: Penny Haldane
- EPCOR: Stan Yee
- StatoilHydro: Brian Blattler
- UCA: Rick Cowburn
- AESO: John Martin, David Michaud
- Consultant to AESO: Arnie Reimer

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   
2. **Review agenda**
   
3. **Review draft working groups terms of reference**
   - See enclosed document
   - The AESO proposes to revise the first bullet point in section 3 to the following:
     - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
   - Identify any concerns with or revisions required to the terms of reference

**Posted on AESO website**
Terms of reference will be finalized after initial meetings for all working groups are complete.

4 Background for TFO O&M cost causation study 1:30 PM
- Please review the enclosed information before the meeting, if possible:
  (a) Directions 4D and 20A on analysis of TFO O&M costs, from pages 23 and 69 respectively in Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
  (b) AESO’s responses to Directions 4D and 20A in its 2005-2006 General Tariff Application Refiling, filed on September 27, 2005
  (c) Discussion of TFO operations, maintenance, and administration costs in sections 7 and 8 (pages 54-56) of the 2006 Transmission Cost Causation Update, filed as an appendix to the AESO’s 2007 General Tariff Application on November 3, 2006
  (d) Discussion of TFO operations, maintenance, and administration costs in section 4.3.3 (pages 12-13) of the AESO’s 2007 General Tariff Application, filed on November 3, 2006
  (e) Directions 2, 6, and 18 on analysis of TFO O&M costs, from pages 25, 58-59, and 105-107 respectively in Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (f) AESO’s responses to Directions 2, 6, and 18 in its 2007 General Tariff Application Refiling, filed on February 1, 2008

5 Scope of TFO O&M cost causation study 1:50 PM
- See enclosed draft proposal for study of electric transmission system operating and maintenance costs

6 Methodology to functionalize TFO O&M costs 2:10 PM
- What approaches could be used to functionalize TFO O&M costs as bulk system, local system, or point of delivery?

7 Methodology to classify TFO O&M costs 2:25 PM
- What approaches could be used to classify TFO costs as demand-related, energy-related, or customer-related?

8 Follow-up required for next meeting 2:40 PM
- Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s) 2:50 PM

10 Adjourn 3:00 PM

This agenda and all other printed information related to the TFO O&M Cost Causation Study Working Group is available on the AESO's website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders' participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2471 or david.michaud@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: David Michaud, Manager, Regulatory, AESO
    Arnie Reimer, TFO O&M Study, Consultant to AESO
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
- Substations included in POD cost data set
- Inflation index to escalate POD cost data to 2010
- Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
- Respond to AUC directions on analysis of TFO O&M costs
- Determine if TFO O&M costs are energy-related
- Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
- Methodology to analyze and assess design of operating reserve charge
- Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
- Rate design principles for Fort Nelson and similar services
- Cost allocation approaches between BC and Alberta loads in the Rainbow Area
- Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
- Rate design principles for higher-priority export and import services
- Similarities and differences between domestic and intertie services
- Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
- Rate design principles for deferral account riders
- Practicality of improving allocation accuracy of deferral account riders
- Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
The nature of a transmission facility is such that the facility is sized to meet the forecast demand, and a conductor optimization study is typically performed to determine the optimum conductor size to optimize losses. (p. 36)

The cost of a substation was assessed with a normal efficiency transformer, and a high efficiency transformer that may be suitable for a high load factor customer. (p. 43)

These excerpts indicate that planners do study the efficient expansion of the transmission system, and that there are capital costs associated with energy efficiency in both conductors and transformers. However, Mr. Reimer described (T0834) the difficulty in recreating history to determine precisely what embedded costs would have been associated with energy efficiency. Given these challenges, a simplified approach was taken in the Transmission Cost Causation Study to assess costs associated with energy efficiency. The AESO submits that costs are incurred to optimize losses on the transmission system…

Parties also questioned the use of CLMS to moderate the demand charge otherwise called for. With respect to this matter, the Board notes that the TCCS appears to have studied only two of many bulk lines in its analysis. IPCAA has argued that one of the two lines studied, the Edmonton-Calgary line, had significant loading caused by opportunity service at the time of CLMS. Indeed, the Board observes that Mr. Reimer, as referenced above, has acknowledged that CLMS may be expected to be more coincident with system peak. As such, the discount that Mr. Reimer proposes in demand related charges may not be fully justified. 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.

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.

The Board also notes the following from the TCCS: While transmission planning models consider one point in time, transmission planning criteria are based on experience and judgment to ensure reliable operations year round, and planners will optimize conductor size in order to minimize the total cost of wires and losses. The transmission planning process is often used as justification for classification of all wires costs by demand, because transmission planners consider demand under various scenarios. In the event that transmission planning criteria are violated, the transmission system is upgraded to accommodate the forecast demand. However, transmission planning criteria are based on experience and judgment, and therefore, it is too simplistic to classify transmission costs as completely demand related.

37 AltaLink 2004-2007 GTA Application
38 TCCS, page 34
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.

While the Board considers that the prepaid O&M charge may be improved with further research, the Board considers that the adoption of a 12% surcharge as proposed by the AESO is a good starting point for the purposes of the 2006 Tariff.

Accordingly, the Board directs the AESO in its refiling Application to apply the 12% prepaid O&M surcharge such that:

- The surcharge will be determined separately for the optional and non-optional facilities;
- The portion of a DTS interconnection project’s prepaid O&M surcharge based on cost of the optional facilities will be fully charged out to the interconnecting DTS customer, consistent with the Board’s disposition of other optional facility costs; and,
- The portion of the prepaid O&M surcharge related to non-optional facilities is added to other non-optional facility costs and evaluated against the maximum investment function to determine the amount of customer contribution that may be required in respect of the standard facility portion, if any.

While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application

6.2 Generator System Contribution

Subsection 17(2) of the Transmission Regulation requires the AESO to collect, in its tariff, a system contribution charge of $10,000/MW from the owners of new generators for system upgrades to existing transmission facilities required as a result of a generator’s entry on to the AIES grid. This subsection further directs the AESO to collect a system contribution charge of no more than $40,000/MW from the owners of new generators who locate in areas of the transmission system where generation exceeds load, with the amount to be based on the location of the new generating unit relative to the load.

Subsection 17(4) of the Transmission Regulation directs the AESO to include in its tariff, a provision for the refund to the owner of a generating unit who paid system contribution charges pursuant to Section 17. The refund must be received over a period of 10 years from the date it was paid unless the operation of the generating unit failed to meet satisfactory performance standards as set forth in rules to be developed by the AESO pursuant to Subsection 17(5).

In its application, the AESO proposed to refund generator system contributions by way of 9 equal payments spread out over the 10 year period. The AESO explained that its suggested proposal was created to allow for the event that an owner of a generator might experience
Direction
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. [p. 23]

Response
The AESO will include the directed analysis in a future cost causation study of the transmission system.
Direction
While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application. [p. 69]

Response
The AESO will reflect further analysis in the design of an appropriate prepaid operations and maintenance surcharge no later than its 2008 GTA.
7. OPERATIONS, MAINTENANCE AND ADMINISTRATION

The TCCS study was based on the assumption that OM&A costs were proportional to property. This assumption was made because OM&A costs are a small part of the total revenue requirement, and additional data was unavailable. OM&A accounts for approximately 25% to 33% of the total revenue requirement for a TFO.

One concern of interveners is that some facilities are older than others, and that OM&A should be studied to reflect the vintages that exist. A high level review of depreciation studies shows that substation facilities and transmission facilities have a similar remaining composite life. Based on similar remaining composite lives, it is not apparent that some facilities would have significantly different levels of OM&A costs associated with their operation.

TFO GTA’s contain some information regarding the components of OM&A but this information is insufficient to functionalize OM&A costs in alignment with the functional definitions in use in the TCCS Study. Additional study would be required to determine the OM&A of facilities as they age. Conventional wisdom indicates that OM&A costs increase as facilities age and this relationship for facilities in Alberta must be understood to properly functionalize these costs.

The OM&A costs were not studied because work was focused in other areas such as classification of Bulk System costs. A study of OM&A costs must ensure that functionalization of OM&A costs is aligned with the functions in the cost study, and that the current distinction between Local System and POD system may change.

OM&A costs may vary by vintage, whereby old facilities require more funds to maintain than do newer facilities. OM&A costs may also vary by equipment type, whereby substation equipment requires a different types of
maintenance than do transmission lines (vegetation management is required for lines while switch gear maintenance applies only to substations).

The breakdown of AltaLink and Atco Electric TFO facilities show that each function has a different make up of equipment type as follows:

Table 6  Transmission Facility Type by Function

<table>
<thead>
<tr>
<th></th>
<th>Bulk</th>
<th>Local</th>
<th>POD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation</td>
<td>43.6%</td>
<td>10.8%</td>
<td>90.9%</td>
</tr>
<tr>
<td>Line</td>
<td>53.4%</td>
<td>86.6%</td>
<td>5.8%</td>
</tr>
<tr>
<td>General</td>
<td>3.0%</td>
<td>2.5%</td>
<td>3.3%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

The relative age of equipment is estimated by dividing the accumulated depreciation by the property, plant and equipment amount. The AltaLink data for 2003 shows that both transmission lines and substations have accumulated depreciation of between 50% and 60%, indicating that the relative ages are similar.

Table 7  Depreciation of Transmission Facilities

<table>
<thead>
<tr>
<th></th>
<th>2003 PPE</th>
<th>2003 Acc Dep</th>
<th>Acc Dep % of PPE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substations</td>
<td>659.7</td>
<td>343.5</td>
<td>52.1%</td>
</tr>
<tr>
<td>Lines</td>
<td>657.3</td>
<td>388.4</td>
<td>59.1%</td>
</tr>
</tbody>
</table>

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about $\frac{1}{4}$ of the revenue requirement,

- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,

- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.
8. RECOMMENDED ADDITIONAL ACTIVITIES

Local System and POD

Further study regarding the distinction between Local System and POD should be completed following the review of the Customer Contribution Policy.

The TCCS study proposed a distinction between Local System and POD that aligns with the concept of common facilities (useful to more than one point of delivery) and dedicated facilities (dedicated to one point of delivery). The Customer Contribution Policy uses different distinctions.

If definitions are refined, the TCCS should be reviewed and updated. This updated study would provide a new basis for the fixed and demand related costs associated with POD’s.

OM&A

A new study of OM&A should be conducted to facilitate the functionalization of OM&A. The relationship between age and OM&A should be studied as well as the relationship between OM&A and equipment type. This study would provide for an improvement in the functionalization of approximately ¼ of the transmission revenue requirement.

The data required for such a study is not currently available. The development and compilation of this data would require a considerable effort and would require details of O&M expenditures by facility and by equipment type over the life cycle of transmission and substation equipment. Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.
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.

Some parties suggested costs of the bulk system be recovered based on the coincidence of loads in a region with bulk line loading in the region. The AESO does not consider a regional cost analysis permissible under the Electric Utilities Act, which requires the AESO to recover costs on a “postage stamp” basis for all customers.

The AESO also does not consider it appropriate to recover bulk system costs wholly on an energy basis. An energy ($/MWh) charge indicates that total throughput on the bulk system is the most important cost consideration. This is clearly not the cost driver for the bulk system; individual bulk lines and other equipment are designed to meet maximum demand requirement, not total throughput.

The billing determinant which appropriately recognizes that demand in every hour is important is non-coincident peak (NCP) demand, defined as highest metered demand in the AESO’s DTS rate. NCP cost recovery signals that demand in any interval during the billing period could cause costs on the bulk system. Similarly, since there are no distinct monthly usage patterns on the bulk system, demand in any month could cause costs on the bulk system. The AESO therefore considers it appropriate to incorporate a demand ratchet in the bulk system billing determinant. Finally, to the extent that the bulk system is planned to meet future loads on the system as indicated in part by customers’ contracted capacity, the AESO considers that bulk system billing should include a contract capacity component.

Highest metered demand, demand ratchet, and contract capacity constitute the billing capacity used for the demand component of the local system and POD charges in the current DTS rate. The AESO proposes that billing capacity also is an appropriate billing determinant for the recovery of bulk system costs. The billing capacity determination is proposed to remain the same as in the current DTS rate; that is, it 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.

The specific moderation of the demand charge questioned in Direction 4C is addressed in section 4.5.1 of this application, which discusses the design of the system charge in the DTS rate.

4.3.3 Operations, Maintenance, and Administration Costs

In responding to Direction 4D of Decision 2005-096, PS Technologies reviewed the functionalization and classification of operations, maintenance, and administration (OMA) costs within the Transmission Cost Causation Study. The Update considered that OMA costs could vary by equipment vintage and type, but noted that data was not available to refine the functionalization and classification of OMA costs. In any event, the Update concluded the impact on total cost functionalization and classification would be expected to be small because OMA costs account for about one-quarter of TFO revenue requirements, all equipment involves a similar mix of vintages, and the largest cost function (bulk system) contains relatively equal amounts of line and substation equipment. No changes to the
transmission cost functionalization and classification were recommended as a result of the review of OMA costs.

4.3.4 Transmission Point of Delivery Cost Classification

The *Transmission Cost Causation Update* examined the classification of point of delivery costs, defined to include substations providing service to load customer and radial lines, if any, associated with such substations. The original *Transmission Cost Causation Study* included a zero intercept analysis to classify 56.2% of point of delivery costs as customer-related costs, and a minimum system analysis to classify the remaining costs 43.1% as demand-related and 0.7% usage-related. However, the data relied upon for the analysis exhibited significant scatter that could not be examined in detail using historical transmission facility information.

While discussing the AESO’s maximum investment formula in Decision 2005-096, the EUB determined “that cost...is the appropriate starting point for establishing the investment policy.” (p. 56) The EUB ultimately directed and approved an investment policy derived from the point of delivery cost information included in the *Transmission Cost Causation Study*. However, in Direction 13A the EUB also required the AESO to analyze additional data to recommend a maximum investment function, as provided in section 6 of this Application.

The same costs (essentially those comprising the point of delivery function) ultimately underlie both the DTS POD charge and the AESO investment function. The AESO therefore developed both aspects of its tariff together, and relied primarily on the detailed examination of the point of delivery cost data conducted during development of the maximum investment function.

Analysis of point of delivery cost data in the *Customer Contribution Study* (as also discussed in section 6) found that those costs can be reasonably represented by the following cost function:

\[
\text{Point of Delivery Costs} = 0.947 \text{ million} \]  
\[+ (0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity})\]  
\[+ (0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})\]  

This cost function is primarily based on detailed examination of 30 projects representing a total DTS capacity of 516.7 MW and total project costs of $213.2 million, and utilizes a linear regression analysis to determine an average cost function.

However, the projects in the data set did not include any interconnections with DTS capacities less than 7.5 MW. To determine a cost function for such smaller projects, the AESO adapted a minimum-intercept method using a small subset of POD cost information included in the *Transmission Cost Causation Study*. The minimum-intercept approach relates installed cost to capacity by creating a curve for various capacities using regression techniques and then extending the curve to a no-load intercept. This was the approach used to establish the fixed and first 7.5 MW components in the point of delivery cost function provided above.
Table 1. 2006 Functionalized and Classified Wires Costs (“Updated” % of Total)

<table>
<thead>
<tr>
<th>Classification</th>
<th>Total</th>
<th>Demand</th>
<th>Usage</th>
<th>Customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>41.7%</td>
<td>34.0%</td>
<td>7.7%</td>
<td>-</td>
</tr>
<tr>
<td>Local System</td>
<td>17.4%</td>
<td>14.3%</td>
<td>3.0%</td>
<td>-</td>
</tr>
<tr>
<td>POD</td>
<td>40.9%</td>
<td>17.6%</td>
<td>0.3%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>66.0%</td>
<td>11.0%</td>
<td>23.0%</td>
</tr>
</tbody>
</table>

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.69

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.70

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

69 Ex. 012, TCCU, p. 52
70 Decision 2005-096, p. 26
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 thought 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.\(^\text{193}\)

The AESO noted 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

\(^{193}\) Decision 2005-096, p. 23
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. 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.

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. 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.

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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343 Ex. 098, AESO AE-3, pages 2-3 of 4; Tr 847
344 Ex. 007, Application Section 6.5.2, pp. 13-15
345 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 filing 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. 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 and a demonstration of commitment. 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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346 Tr. Vol. 2, p. 348, line 18 to p. 349, line 2, p. 360, line 20 to p. 367, line 1
347 Tr. Vol. 4, p. 861, line 13
348 Tr. Vol. 4, p. 864, lines 2-9
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.
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.
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.
Draft Proposal for Study of  
Electric Transmission System Operating and Maintenance Costs  
Arnie Reimer

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

Scope:

Produce a report for the AESO that will be part of the next AESO GTA outlining operating and maintenance costs of electric transmission systems. The report will address Directive #6 in the EUB Decision 2007-106. The report will study and provide recommendations for the functionalization and classification of O&M costs for use in AESO’s transmission tariff design.

1. Identify Total Revenue Requirement for four largest TFO’s in Alberta for 2 or 3 historical years, by year:
   a. Breakdown of costs into capital and O&M
   b. Breakdown of O&M costs

2. Study of O&M Costs
   a. Over the service life of the facilities
   b. By the type of facilities
      i. Transmission lines,
      ii. Substations and switching apparatus,
      iii. Transformers,
      iv. Protection and Controls,
      v. Telecommunication,
   c. By type of operation/maintenance,
      i. Predictive, preventative,
      ii. Time, condition, operation based and reliability centered,

3. Develop relationship of:
   a. O&M costs in relation to capital costs
   b. O&M costs in relation to transmission functions
      i. Bulk
      ii. Local,
      iii. POD
c. O&M costs in relation to:
   i. Demand related,
   ii. Energy related,
   iii. Fixed

Schedule and Cost:

The time to complete the study is estimated at six months. Within this period, there will be requests to TFO’s for cost information, and time will be required for response. Following the compilation of data, stakeholder information sessions will be held to update stakeholders as to progress and direction as well as preliminary results. Stakeholders will be afforded an opportunity to provide input.
June 29, 2009

DTS Operating Reserve Charge Design Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for DTS Operating Reserve Charge Design Working Group

The second meeting of the DTS Operating Reserve Charge Design Working Group for the AESO’s 2010 tariff application is scheduled as follows:

Time: 1:30 to 3:30 PM
Date: Monday, June 29, 2009
Location: Meeting Room 2538, AESO Office, 330 – 5th Avenue SW, Calgary
Refreshments: Coffee, juice, and snacks

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. ADC has already advised that they will participate in this meeting by conference call, and UCA are unable to attend this meeting.

The agenda for the meeting is proposed to include the following items:

1 Review agenda 1:30 PM

2 Feasibility of hourly allocation of operating reserve costs 1:35 PM
   • Based on discussion at the first meeting, the AESO has investigated the possibility of allocating operating reserve costs in each hour, at the end of the month
   • It appears feasible to implement such an approach:
     — all costs are incurred hourly
     — all required information is currently available, although in different systems
     — all required information is available early enough in the month to allow inclusion on preliminary statements issued on the fifth business day of the month
   • Cost and time required for implementation are not known, but costs are expected to be reasonable and timing should be feasible in the context of a tariff application
   • The AESO therefore plans to propose an hourly allocation of operating reserve costs as part of its 2010 tariff application

3 Exceptions to hourly allocation of operating reserve costs 2:00 PM
   • Non-compliance charges and liquidated damages are incurred hourly but are not known until the month following the billing period
- The AESO proposes such amounts, which totaled about a $7 million credit in 2008, be refunded to customers through Rider C with subsequent annual reconciliation after year-end.
- Small changes to costs due to volume restatements and other adjustments are expected to occur after the billing period; the AESO proposes such adjustments also be collected or refunded through Rider C with subsequent annual reconciliation after year-end.

4 Proposed DTS operating reserve charge
- The AESO proposes the following wording for the operating reserve charge in the DTS rate:

  The Operating Reserve Charge equals:
  - Metered Energy in each hour × operating reserve unit cost

  where operating reserve unit cost is the total cost of operating reserves in the hour divided by the sum over all DTS customers of the Metered Energy for each customer in the hour.

- Approach is consistent with energy classification of operating reserve costs.

5 Estimates of operating reserve charges
- The AESO proposes to continue to calculate a simple percentage of pool price charge as in the current DTS rate, to allow a customer to estimate their bill and to allow the AESO to determine security requirements.
- The same percentage of pool price charge will be used to determine the operating reserve component that is included in opportunity rates (demand opportunity service and export opportunity service).
- The AESO does not propose to pursue the two-block rate for the purposes of estimating operating reserve charges.

6 Availability of operating reserve charge information
- The AESO proposes to post on its historical reports page information that would allow a customer to validate the operating reserve charge.
- Information would consist of total operating reserve costs in each hour, total DTS metered energy in each hour, and operating reserve unit cost as defined in the DTS rate (total costs divided by total energy).
- At this point the AESO does not propose to distribute that information with billing CSV files.

7 Follow-up required
- What consultation to general stakeholders should be undertaken?
- Summarize what tasks need to be completed and who will complete them.

8 Dates and times for next meeting(s)

9 Adjourn

This agenda and all other printed information related to the DTS Operating Reserve Charge Design Working Group is available on the AESO's website at www.aeso.ca by following the
path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or HYPERLINK "mailto:john.martin@aeso.ca?subject=AESO%202020%20Tariff%20Application%20Question" , or Raj Sharma at 403-539-2632 or HYPERLINK "mailto:raj.sharma@aeso.ca?subject=AESO%20OR%20Charge%20Working%20Group" .

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Raj Sharma, Senior Tariff Analysis, AESO
June 4, 2009

DTS Operating Reserve Charge Design Working Group Members
AESCO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for DTS Operating Reserve Charge Design Working Group

The first meeting of the DTS Operating Reserve Charge Design Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 1:00 to 3:00 PM
- **Date:** Friday, June 5, 2009
- **Location:** Meeting Room 2538, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, and soft drinks

This working group includes the following members:
- ADC: Colette Kearl
- AltaLink: Hao Liu
- ENMAX: Randy Stubbings
- IPCAA: Vittoria Bellissimo
- TransCanada: Vince Kostesky
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   - **Time:** 1:00 PM

2. **Review agenda**
   - **Time:** 1:10 PM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
     - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for DTS operating reserve charge design

- Please review the enclosed information before the meeting, if possible:
  (a) Discussion of ancillary services cost classification in section 4.3 (pages 11-15) of the AESO’s 2006 General Tariff Application, dated January 28, 2005
  (b) Discussion of ancillary services cost classification in section 5.4 (pages 24-25) of Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
  (c) Discussion of ancillary services 2008 cost variances in section 3.1.2 (pages 34-37) of the AESO’s 2008 Deferral Account Reconciliation Application, filed on April 9, 2009 (incorrectly dated April 9, 2008)

- The following costs were included in Table 2-2 in the AESO’s 2009 Rates Update Application (filed on March 12, 2009) for recovery through the operating reserve charge.

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<td>Approved U2008-217</td>
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<td>28 Jan 2009</td>
<td>Decision</td>
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<td><strong>9.7</strong></td>
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</table>

Other Ancillary Services

- **Brazeau Fast Ramp (Previously GRAS)**
  - 2009 AEO Board
  - 2008
  - 2007

- **Black Start**
  - 2009 AEO Board
  - 2008
  - 2007

- **Generator Remedial Action Schemes (RAS)**
  - 2009 AEO Board
  - 2008
  - 2007

- Costs Included in Operating Reserve Charge
  - 238.4
  - 238.4
  - 217.9
  - 125.2

- Is there other background that participants consider particularly relevant?
5  **DTS operating reserve charge discussion paper** 1:30 PM
   • See enclosed discussion paper for proposed approach to revising DTS operating reserve charge
   • Review content of discussion paper
   • Discuss process to finalize discussion paper, including inviting comments from larger stakeholder audience

6  **Potential hourly allocation of operating reserve costs** 2:00 PM
   • Can all operating reserve costs be allocated on an hourly basis?
   • What visibility of data would customers require for verification of operating reserve charges?
   • Are accurate operating reserve charges required for preliminary statements issued on the 5th business day of month?
   • How can adequate time be created to allow the AESO to calculate bills when operating reserve costs are finalized at the same time as DTS bills are issued?
   • What is needed to address these and other questions if hourly allocation of operating reserve costs is pursued?

7  **Follow-up required for next meeting** 2:45 PM
   • Summarize what tasks need to be completed before next meeting and who will complete them

8  **Dates and times for next meeting(s)** 2:55 PM

9  **Adjourn** 3:00 PM

This agenda and all other printed information related to the DTS Operating Reserve Charge Design Working Group are available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AEO 2010 Tariff Consultation Working Groups  
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update  
   - Substations included in POD cost data set  
   - Inflation index to escalate POD cost data to 2010  
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study  
   - Respond to AUC directions on analysis of TFO O&M costs  
   - Determine if TFO O&M costs are energy-related  
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge  
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services  
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area  
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services  
   - Similarities and differences between domestic and intertie services  
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders  
   - Practicality of improving allocation accuracy of deferral account riders  
   - Possible integration of Riders B and C
(g) Tariff Changes Related to Transition of Authoritative Documents (TOAD)
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) Amortized Customer Contribution Option and Other Contribution Provisions
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) Tariff Provisions Related to Customer-Owned Substations
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
The classification of ancillary services costs, however, has been adjusted from that underlying the current tariff, based on the results of an ancillary services cost study discussed more fully in the following section.

The classification of costs for DTS customers is provided in Schedule 5.3, and for STS customers in Schedule 5.5.

4.3 Ancillary Services Cost Study

In Decision 2001-32 on the ESBI Alberta Ltd. (EAL) 2001 General Tariff Application Phase II Matters, the EUB provided the following direction:

10. Therefore, the Board directs EAL, in the 2003 GTA, to file a more detailed and accurate cost of service study for system support services. Further, the Board directs that this cost of service study should contain the rationale for the allocation of each one of the following SSS [system support services] cost components:
   - Operating Reserves (including regulating reserves, spinning reserves and supplemental reserves)
   - Generator RAS and Black Start
   - Load Following
   - Voltage Control (including TMR/SMR, hydro motoring, and ATCO Power’s Poplar Hill’s plant)
   - Remedial Action Schemes (including ILRAS)

11. The Board also directs EAL, in the 2003 GTA, to include rate proposals for unbundling SSS and proposals for customer self-supply of SSS.

In accordance with this direction, the AESO commissioned EnVision Energy Consulting Ltd. to prepare an independent Ancillary Services Cost of Service Study (the AS Cost Study), attached as Appendix C to this Application. The study examined the costs incurred by the AESO to provide ancillary services, analyzed the factors that drive ancillary service requirements, and reviewed the match between the AESO’s costs and the revenues derived from the current tariff. After concluding that the current rate structure can lead to mismatches between costs and revenues, the study recommended alternative rate designs which may provide a better match.

Ancillary services costs to the AESO can also be viewed as a function of payments to ancillary service providers, and can be classified for rate design purposes as demand-related or usage-related. The costs could then be recovered through tariffs as fixed or variable charges, in accordance with the classification of the ancillary service payments. Basing rate design for ancillary services solely on alignment with payments to ancillary services providers may not always accord with the cost classification set out in the AS Cost
Study, as cost causation is only one of several rate design criteria. In particular, the AESO is proposing ancillary services rates that also consider rate stability, simplicity of understanding, and economy of billing.

In Decision 2001-32, the EUB also noted “that the first step to self-provision [of ancillary services] is to unbundle the various system support services in the TA’s tariff” (p. 41) and provided Direction 11 to “include rate proposals for unbundling SSS and proposals for customer self-supply of SSS” (p. 59). Based on the AS Cost Study and rate design considerations, the AESO proposes to unbundle certain ancillary services. The AESO recognizes that each of the many individual ancillary services (as detailed in the AS Cost Study) could be identified separately in the rate schedule, but considers such detailed unbundling would be premature and would unnecessarily complicate billing during the time that the market for such services is developing. For example, the AS Cost Study concludes that the cost of regulating reserves should be classified in accordance with customers’ ranges of demand over a given period. Rates designed on this basis would degrade rate stability on an individual customer basis, and would also increase billing costs as extensive information system changes to the billing and metering systems would be required to support the resulting tariffs.

Accordingly, the AESO has unbundled ancillary services into three separate and distinct tariff charges categorized by separate cost recovery approaches:
(a) operating reserves charge, structured as a usage charge which varies as a percentage of pool price, averaged over all hours;
(b) voltage control charge, structured as a flat (non-varying) usage charge; and
(c) other system support services charge, structured as a demand charge.

**Operating reserves** — Operating reserves consist of regulating reserves (including load following) and supplemental and spinning reserves (“contingency reserves”).

Regulating reserves in Alberta track variations in load that cannot be met with energy dispatches. Volumes of regulating reserves are specified as a range in MW over which a level of control is required by the automatic generation control system. The AS Cost Study concludes that regulating reserves are a function of the variability, or range, of Alberta Interconnected Electric System (AIES) load in each hour. The AESO’s operating policies have established a minimum regulation range — the difference between system supply and demand — of 110 MW. As the AESO makes payments to generators that assist the AESO in balancing supply and demand within that regulation range, the cost of regulating reserves is determined by the variability in the regulating range. Consequently, the AS Cost Study classifies regulating reserves as the range in demand over each hour.

Supplemental and spinning reserves are used to restore frequency following the loss of generation in Alberta or the Western Electricity Coordinating Council (WECC) area. In Alberta, the supplemental and spinning reserves requirement is primarily a function of the
AIES firm load responsibility served by hydro and thermal generation. The AS Cost Study concludes that costs of contingency reserves should therefore be classified as flat usage.

The AS Cost Study further concludes that the AESO’s costs to procure operating reserves are dependent on several volatile inputs that are not correlated with each other. To avoid passing this volatility through to rates, the AESO is proposing to continue to recover these costs through an average all-hours percent of pool price, as approved in EUB Decision 2001-49 on the EAL 2001 GTA Final Rates and Tariffs.

**Generator remedial action schemes (RAS) and black start** — Generator RAS is used to restore and maintain power system frequency at acceptable levels. Black start service is obtained from suppliers that have the ability to self-start, energize lines, and provide start-up power to other generators thereby enabling timely restoration of electrical supply on the AIES in the event of a blackout. AESO payments for generator RAS and black start account for a minimal portion of the AESO’s costs to procure ancillary services.

The AS Cost Study states that black start would be used to quickly restore loads that were on the system immediately prior to the outage and therefore hourly usage is the appropriate billing determinant. The AS Cost Study provides no conclusions on cost classification in respect of Generator RAS. Generator RAS and black start costs are currently recovered through energy multiplied by a percent of all-hours pool price, and the AESO proposes to continue this approach.

**Transmission Must Run (TMR)** — TMR is generation required by the AESO to be on-line and running at specific outputs in order to ensure system security. The AS Cost Study includes a detailed review of TMR costs, which — with the exception of Invitation to Bid on Credits (IBOC) contracts — are tied to a combination of hourly gas prices, pool prices, heat rate, and output. The study considers the mismatch between the AESO’s costs to procure TMR, which are inversely proportional to pool price, and the AESO’s current recovery of those costs, which is directly proportional to pool price. Consequently, the AS Cost Study recommends that although TMR costs can be classified as usage related, recovery as a percent of pool price is inappropriate as revenues would increase with pool price — the opposite effect of payments to TMR suppliers.

Conceptually, cost recovery of reactive power payments through a demand charge could be appropriate, such as that for Poplar Hill, but the AESO does not pay generators for reactive power dispatches. Consequently, the AESO proposes to recover TMR costs as a component of the voltage control charge, structured as a flat (non-varying) usage charge.

**Under-Frequency Mitigation** — If a contingency on the transmission system causes frequency to decline beyond what can be arrested through other actions, load is tripped off through a coordinated automatic under-frequency load shedding program. The AESO’s payments to the under-frequency mitigation service providers are in the form of $/MW amounts. Based on the $/MW structure of payments, the AESO proposes to classify under-
frequency mitigation costs as 100% demand-related. This is a change from the current recovery of under-frequency mitigation costs as 100% varying usage (energy multiplied by a percent of all-hours pool price).

Hydro Motoring — Hydro motoring services are no longer purchased by the AESO.

Poplar Hill — The Poplar Hill generator provides TMR generation and voltage support to loads in northwestern Alberta. The AS Cost Study concludes that as payments for Poplar Hill services are fixed in nature, the current classification of Poplar Hill costs as 100% demand-related should be maintained.

Interruptible load remedial action scheme (ILRAS) — The AESO uses ILRAS to increase the import capability of the Alberta-BC interconnection. If the Alberta-BC tie trips concurrent with high import levels, ILRAS loads will automatically trip to limit frequency decline and prevent shedding of other load in Alberta. ILRAS has traditionally been considered a replacement for wires and classified accordingly, but the AS Cost Study notes that ILRAS may alternatively be considered to replace contingency reserves for imports and could accordingly be similarly classified, as usage-related.

The AS Cost Study concludes that the cost of ILRAS is relatively small, and that there are no material rate impacts regardless of how costs are allocated. The AESO therefore proposes the current classification in the same proportion as wires costs should be maintained, and proposes to classify the costs 46.6% to demand and 53.4% to flat usage.

The proposed ancillary services cost unbundling and related cost classification changes are provided in Table 4.3.1.

Customer self-supply of ancillary services — Customer self-supply is a component of the Wholesale Market Review currently underway. The AESO considers it prudent to wait for the outcome of this review and attendant legislation before setting out a proposal for customer self-supply of ancillary services. Consequently, the AESO seeks leave of the EUB to address customer self-supply of ancillary services at a future date.
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<thead>
<tr>
<th>Ancillary Service</th>
<th>Current Classification</th>
<th>Proposed Classification</th>
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<td>Poplar Hill</td>
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<tr>
<td>ILRAS</td>
<td>60%</td>
<td>40%</td>
</tr>
</tbody>
</table>

Notes: MW indicates classification as demand
MWh indicates classification as flat (non-varying) usage
% of PP indicates classification as usage varying as percentage of pool price
Changes in classification are indicated in **bold** in the table
Classification of ILRAS changes to reflect the change in classification of wires costs
The MWh component of ILRAS is recovered in the DTS rate schedule as part of the DTS Interconnection Charge, to avoid a small $/MWh component in the OSS Services Charge

4.4 Rate Design

Based on the cost allocation and classification outlined in Sections 4.1, 4.2, and 4.3, rate components for DTS and STS are calculated in Schedules 5.4 and 5.6 respectively. Schedule 5.7 provides the 2006 forecast billing determinants on which the rates are based.

Finally, Schedule 5.8 provides a comparison of the proposed changes by rate component, as compared to current interim rates (effective as of January 1, 2005).

Beyond the changes arising from the calculation of DTS and STS rate components to recover the 2006 revenue requirement, the structure of the AESO’s rates remains generally unchanged. Other changes are discussed in the following sections, including the change to DTS billing capacity ratchet levels, Fort Nelson rate schedules, elimination of Demand Opportunity Service (1 Hour), Export Service and Import Service, the Primary Service Credit, and Losses Calibration Factor Rider E.
Given the above, the Board is prepared to accept that some portion of embedded wires costs are energy related. The Board also notes that preparing a cost of service study for transmission on a stand alone basis is a relatively new and unique process. The Board acknowledges the difficulties faced by Mr. Reimer in preparing his analysis and in the circumstances the Board considers the TCCS to be a good first step and is willing to accept its recommendations in the Board’s approved rate design.

5.4 Ancillary Services Cost of Service Study

In response to Directions 10 and 11 of Decision 2001-32, the AESO filed an Ancillary Services Cost of Service Study. The study was prepared by Mr. Randy Stubbings of Envision Consulting and was summarized at pages 11-15, Section 4 of the Application.

The AESO’s proposed classification was summarized in Table 4.3.1 of the Application and is reproduced below.

The AESO explained the results of the study and their proposal as follows:

Ancillary services costs to the AESO can also be viewed as a function of payments to ancillary service providers, and can be classified for rate design purposes as demand-related or usage-related. The costs could then be recovered through tariffs as fixed or variable charges, in accordance with the classification of the ancillary service payments. Basing rate design for ancillary services solely on alignment with payments to ancillary services providers may not always accord with the cost classification set out in the AS Cost Study, as cost causation is only one of several rate design criteria. In particular, the AESO is proposing ancillary services rates that also consider rate stability, simplicity of understanding, and economy of billing.

In Decision 2001-32, the EUB also noted “that the first step to self-provision [of ancillary services] is to unbundle the various system support services in the TA’s tariff” (p. 41) and provided Direction 11 to “include rate proposals for unbundling SSS and proposals for customer self-supply of SSS” (p. 59). Based on the AS Cost Study and rate design considerations, the AESO proposes to unbundle certain ancillary services. The AESO recognizes that each of the many individual ancillary services (as detailed in the AS Cost Study) could be identified separately in the rate schedule, but considers such detailed unbundling would be premature and would unnecessarily complicate billing during the time that the market for such services is developing. For example, the AS Cost Study concludes that the cost of regulating reserves should be classified in accordance with customers’ ranges of demand over a given period. Rates designed on this basis would degrade rate stability on an individual customer basis, and would also increase billing costs as extensive information system changes to the billing and metering systems would be required to support the resulting tariffs.

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b) voltage control charge, structured as a flat (non-varying) usage charge; and

c) other system support services charge, structured as a demand charge.

Application, Section 4, pages 11-12
Table 4.3.1 Proposed Ancillary Services Charges and Classification

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<tr>
<th>Ancillary Service Component</th>
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Classification of ILRAS changes to reflect the change in classification of wires costs
The MWh component of ILRAS is recovered in the DTS rate schedule as part of the DTS Interconnection Charge, to avoid a small $/MWh component in the OSS Services Charge
ILRAS Interruptible Load Remedial Action Scheme

5.4.1 Classification of Ancillary Services

The only party to submit any comments with respect to the AESO’s proposal was FIRM. FIRM maintained that TMR costs should be allocated on a basis more reflective of cost causation and recommended that the AESO rate design for the TMR component of voltage control reflect the 1:2 ratio of TMR costs for DTS-MWH on-peak and off-peak charges. FIRM acknowledged such a muted price signal would not significantly affect customer consumption behavior but claimed it would better reflect cost causation.

In reply the AESO submitted that if a price signal is so muted that it will not affect customer behaviour, then there is little point in providing such a signal. If such a unique bill charge will vary by so little compared to an all-hours average charge and will seem illogical to many customers (as explained by Mr. Martin at T0657-58), then the AESO submitted there was no justification to warrant its implementation.

The Board agrees with the AESO and approves the recovery of TMR costs on a flat usage basis. Consistent with the Board’s determinations with respect to classification of wires costs, the costs for ILRAS should be classified as 80% demand and 20% energy. The demand portion should be allocated on the same basis as the bulk wires.

5.5 Demand Transmission Service Rate Design

5.5.1 Unbundling

The AESO has stated that it considers the level of unbundling proposed in the Application to be adequate and any further steps in this regard should be deferred until the 2007 tariff. The AESO stated that it did not consider a bill containing seven to nine distinct charges to be simple.
Order 2006-315 released on December 15, 2006, which approved EPCOR’s 2007 interim transmission facility owner tariff. The recorded cost was from AUC Decision 2008-125 released on December 3, 2008, which approved EPCOR’s 2007-2009 transmission facility owner tariff on a final basis.

Line 11 KEG Unit Transformers Conversion

The 2008 recorded cost for the KEG unit transformers conversion was $3.3 million. No corresponding amount was included in the approved forecast. The variance arose from directions in AUC Decision 2008-101 regarding AESO recovery of costs for Keephills-Ellerslie-Genesee (“KEG”) conversion of unit transformers, released on October 21, 2008, as discussed in section 12 of this application.

3.1.2 Ancillary Services

The recorded ancillary service costs for 2008 totalled $312.4 million, which is $46.5 million (or 17%) more than the 2008 approved forecast of $265.9 million. The primary component of this variance is an increase in active operating reserves costs of $47.3 million (or 24%) due to more occurrences of high pool price periods and a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves. The variance also includes an increase in standby operating reserves costs, a credit arising from trading fees and other related charges, and reductions in the costs of Brazeau fast ramp, under frequency mitigation, and interruptible load remedial action scheme (“ILRAS”) services.

Explanations of the variances of the 2008 recorded costs from the 2008 approved forecast are provided in the sections that follow.

Lines 17 to 26 Operating Reserves

Operating reserves are unloaded megawatt capacity that is available to respond to temporary shortfalls in supply caused by the loss of a generating unit, intertie capabilities, or moment-to-moment fluctuations in the load. Operating reserves are comprised of regulating reserve and contingency reserves (including spinning and supplemental reserves).

Regulating reserve refers to the amount of synchronized generation that responds to automatic generation control (“AGC”) signals that track moment-to-moment fluctuations in the supply and demand. Regulating reserves track variations in the load that cannot be met with energy dispatches. Because variations in supply and demand can be either positive or negative, regulating reserves have a range with an upper and lower limit. The volumes of regulating reserve are specified as a range in megawatts over which a level of control is required by the AGC system.

Spinning reserve is unloaded generation that is synchronized to the system, automatically responsive to deviations in frequency, and ready to serve additional demand following a System Controller directive within 10 minutes.

Supplemental reserve is unloaded generation, off-line generation, or system load that is ready to serve additional demand (generator) or to reduce demand (load) within 10 minutes of a directive from the System Controller.
Spinning and supplemental reserves are required in order to restore frequency following the loss of generation in Alberta or in the Western Electricity Coordinating Council ("WECC") region. Alberta must comply with WECC policies for maintaining specific volumes of spinning and supplemental reserves in order to maintain reliability.

About 90% of operating reserves volumes are competitively procured through the Alberta Watt Exchange ("Watt-Ex"), an electronic exchange where transactions reflect bids and offers of the AESO and market participants. The remaining 10% of operating reserves volumes are procured directly from suppliers through Over-The-Counter ("OTC") transactions.

Lines 17 to 20 Active Operating Reserves

Active operating reserves are the operating reserves that are forecast by the AESO as necessary to operate the Alberta Interconnected Electric System ("AIES") securely and meet the AESO’s reliability obligations to WECC. 2008 recorded costs were $244.1 million, which is $47.3 million (or 24%) more than the 2008 approved forecast of $196.8 million, and comprised the following amounts:

- For active regulating reserve, the 2008 recorded cost was $70.3 million, which is $14.7 million (or 26%) more than the 2008 approved forecast of $55.7 million.
- For active spinning reserve, the 2008 recorded cost was $94.7 million, which is $20.1 million (or 27%) more than the 2008 approved forecast of $74.6 million.
- For active supplemental reserve, the 2008 recorded cost was $79.1 million, which is $12.5 million (or 19%) more than the 2008 approved forecast of $66.5 million.

The increase in 2008 recorded costs compared to the approved forecast for all active operating reserves primarily results from the competitive determination of price through the operating reserves market. Active operating reserves are generally reflective of pool price, and more high pool price periods occurred in 2008 compared to prior years on which the 2008 forecast was developed. As well, higher recorded costs reflected a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves.

In total, 2008 recorded active operating reserves volumes were 5,614 GWh, which is 154 GWh (or 3%) less than the 2008 approved forecast of 5,768 GWh.

Lines 21 to 24 Standby Operating Reserves

Standby reserves are additional reserves that are available to the System Controller in the event an active provider fails to provide active reserves, or if actual requirements are higher than the active reserve forecast. Payments for standby reserves include a premium paid for the option to activate the standby reserves and a price that is paid if the reserves are activated.

For standby regulating reserves premiums, the 2008 recorded cost was $7.4 million, which is $2.7 million (or 57%) more than the 2008 approved forecast of $4.7 million. For standby regulating reserves activations, the 2008 recorded cost was $1.3 million, which is $0.3 million (or 19%) less than the 2008 approved forecast of $1.6 million.
For standby spinning reserves premiums, the 2008 recorded cost was $4.9 million, which is $1.3 million (or 36%) more than the 2008 approved forecast of $3.6 million. For standby spinning reserves activations, the 2008 recorded cost was $7.1 million which is $3.1 million (or 78%) more than the 2008 approved forecast of $4.0 million.

For standby supplemental reserves premiums, the 2008 recorded cost was $1.9 million, which is $0.5 million (or 36%) more than the 2008 approved forecast of $1.4 million. For standby supplemental reserves activations, the 2008 recorded cost was $3.0 million, which is $0.1 million (or 3%) more than the 2008 approved forecast of $2.9 million.

Standby reserves volumes are only about one to two percent of active reserves volumes. Both standby reserves volumes and activations are quite small, and therefore particularly sensitive to unforecastable real-time conditions, including variances from load forecasts as well as unplanned generation and transmission outages, which affect the availability of active reserves providers. The different standby reserves services may also occasionally be substituted for each other at the time of procurement and result in offsetting volume variances between the different services.

Standby reserves prices are determined by the various offer strategies of the numerous providers involved in the market at any given time. As for active reserves, the cost variances for standby reserves reflected more high pool price periods in 2008 and a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves.

In total, 2008 recorded standby operating reserves volumes were generally consistent with the 2008 approved forecast.

**Line 25 Trading Fees and Other Related Charges**

The 2008 recorded cost for trading fees and other related charges was a credit of $7.4 million. No corresponding amount was included in the approved forecast. The variance arose from unforecasted collections of non-compliance charges of $8.1 million, offset by trading costs to Watt-Ex of $0.7 million.

**Lines 27 to 35 Other Ancillary Services**

Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include Brazeau fast ramp, black start, transmission must run (“TMR”), under frequency mitigation, Poplar Hill, and interruptible load remedial action scheme (“ILRAS”) services.

The 2008 recorded cost of other ancillary services was $50.1 million, which is $0.7 million (or 1%) less than the 2008 approved forecast of $50.8 million, due to prices being lower than forecast for Brazeau fast ramp, under frequency mitigation, and ILRAS services.

Brazeau fast ramp (previously included with generator remedial action scheme (“GRAS”)) service responds to a sudden loss of supply through the automatic and rapid adjustment of Brazeau generator operation. Brazeau fast ramp service stabilizes system frequency after a disturbance to avoid shedding firm load. The 2008 recorded cost of Brazeau fast ramp
service was $0.1 million, which is $0.6 million (or 83%) less than the 2008 approved forecast of $0.7 million due to the expiry of the contract with the Brazeau fast ramp service provider during 2008.

Under frequency mitigation is configured to automatically trip a specific amount of load if the system frequency drops below 59.5 Hz following a system disturbance. The service is procured by the AESO through contracts with service providers. The 2008 recorded cost for under frequency mitigation was $4.0 million, which is $1.0 million (or 20%) less than the 2008 approved forecast of $5.0 million due to contracted MW levels being lowered as a result of a change in operations at service providers’ facilities.

ILRAS supports the import capability of the Alberta-BC interconnection. If the Alberta-BC interconnection trips concurrent with high levels of import, the system will become generation deficient, system frequency will decline, and the AESO will be required to shed load quickly in Alberta to arrest the frequency decline and maintain system reliability. The AESO contracts for loads to automatically trip in these situations to limit the frequency decline and attempt to prevent shedding of additional system load. The 2008 recorded cost for ILRAS service was $0.009 million, which is $0.8 million (or 99%) less than the 2008 approved forecast of $0.8 million due to the continued provision of ILRAS under an early-2007 amendment to the service such that ILRAS is utilized only when the AIES is experiencing or expects an imminent supply shortfall.

The 2008 recorded costs for the remaining other ancillary services (black start, TMR, and Poplar Hill) did not vary significantly from the 2008 approved forecast.

3.1.3 Other Industry Costs

The 2008 recorded other industry costs were $11.5 million, which is $2.4 million (or 26%) more than the 2008 approved forecast of $9.1 million, primarily due to the AESO’s share of AUC overhead being higher than forecast offset by lower recorded external regulatory costs.

Line 37 External Regulatory Costs

External regulatory costs include cost recovery amounts related to the AESO’s regulatory proceedings. The staff, legal, and consulting costs in the administrative costs section of the AESO’s revenue requirement do not include AESO recoverable regulatory costs.

The 2008 recorded external regulatory costs were $0.8 million, which is $3.3 million (81%) less than the 2008 approved forecast of $4.1 million. In 2008, recorded external regulatory costs represented the recoverable costs of the AESO and registered participants related to the AESO’s 2007 general tariff application and Ancillary Services Article 11 negotiated settlement proceedings. The 2008 forecast amount had been based on the estimated cost recovery for several AESO proceedings which did not result in cost awards in 2008, including:

- the AESO’s next general tariff application, now planned to be filed in the third quarter of 2009;
- 2006 and 2007 deferral account reconciliations, incorporated into the 2004-2007 deferral account reconciliation application filed on June 2, 2008;
- recovery of costs for the KEG conversion of unit transformers, filed on April 14, 2008;
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1 Introduction

The AESO’s Tariff was most recently approved in AUC Order U2008-217 concerning the AESO’s 2007 General Tariff Application (“GTA”) filed on November 3, 2006. The tariff includes the use of deferral accounts to ensure no annual profit or loss results from the AESO’s operation. Deferral accounts allow the AESO to address differences between actual revenues and costs incurred in providing system access service to customers. The AESO’s tariff includes Working Capital Deficiency/Surplus Rider B, Deferral Account Adjustment Rider C, and Losses Calibration Factor Rider E, all of which are used to address differences between actual revenues and costs incurred by the AESO.

In the AESO’s Demand Transmission Service (“DTS”) rate, the Operating Reserve (OR) charge is calculated as a product of metered energy in each hour and 3.33% of Pool Price (PP) in that hour. The AESO procures OR from suppliers in the market on behalf of customers using a variety of means. Differences between revenue obtained through the OR charge and costs incurred are dealt with through Rider C. The AESO forecasts the OR revenue and cost shortfall or surplus balance at the end of the upcoming quarter, and then calculates the net amount to be recovered or distributed in that quarter via a Rider C $/MWh charge or credit to reduce the balance to zero.

2 Issue

The currently-approved approach to recovery of OR costs discussed above became effective in 2006. The OR charge was based on forecasted 2006 PP, forecasted 2006 DTS energy volume, and forecasted 2006 OR cost. The 2006 OR rate was 3.87% of PP, was intended to recover the 2006 annual OR cost, and was in effect from January 1, 2006 until July 31, 2008.

For the AESO’s 2007 tariff application, the OR charge was based on forecasted 2007 PP, forecasted 2007 DTS energy volume, and forecasted 2007 OR cost. The 2007 OR rate was 3.33% of PP, was intended to recover the 2007 annual OR cost, and has been in effect since August 1, 2008.

As shown in the table 1 below, actual revenue and cost were substantially different thus requiring that these large difference be dealt with via Rider C. Additionally, Rider C works on a prospective basis and large differences in forecasted and actual quantities resulted in situations where customers were charged significant amounts in one quarter and then refunded significant amounts in the following quarter. Recovery or refund of shortfalls or surpluses through deferral account Rider C is imprecise, as the rider is designed on a simple $/MWh basis. As well, recovery or refund of amounts through Rider C is effectively done on an interim basis, and is “unwound” when deferral account balances are allocated to customers more precisely on a revenue basis in later deferral account reconciliations. If large variances between costs and revenues are addressed through deferral account Rider C, the final allocation to customers in a deferral account reconciliation is subject to greater uncertainty. The deferral account reconciliation also occurs after year-end, several months later than the initial deferral account rider recovery or refund. The deferral account rider process therefore results in timing delays between when costs are incurred to provide system access service and when those costs are finally and accurately recovered from customers.
Table 1 – Actual OR Cost and Revenue

<table>
<thead>
<tr>
<th>Month</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>OR Cost</td>
<td>OR Revenue</td>
<td>Surplus/Shortfall</td>
</tr>
<tr>
<td>January</td>
<td>6.3</td>
<td>13.3</td>
<td>7.0</td>
</tr>
<tr>
<td>February</td>
<td>3.1</td>
<td>8.9</td>
<td>5.8</td>
</tr>
<tr>
<td>March</td>
<td>3.9</td>
<td>8.0</td>
<td>4.1</td>
</tr>
<tr>
<td>April</td>
<td>5.1</td>
<td>7.1</td>
<td>2.0</td>
</tr>
<tr>
<td>May</td>
<td>11.5</td>
<td>9.9</td>
<td>-1.6</td>
</tr>
<tr>
<td>June</td>
<td>11.8</td>
<td>10.7</td>
<td>-1.1</td>
</tr>
<tr>
<td>July</td>
<td>32.6</td>
<td>23.6</td>
<td>-9.0</td>
</tr>
<tr>
<td>August</td>
<td>13.5</td>
<td>13.4</td>
<td>-0.1</td>
</tr>
<tr>
<td>September</td>
<td>18.0</td>
<td>14.5</td>
<td>-3.5</td>
</tr>
<tr>
<td>October</td>
<td>44.5</td>
<td>30.7</td>
<td>-13.8</td>
</tr>
<tr>
<td>November</td>
<td>23.3</td>
<td>19.5</td>
<td>-3.8</td>
</tr>
<tr>
<td>December</td>
<td>11.9</td>
<td>13.5</td>
<td>1.6</td>
</tr>
<tr>
<td>Annual</td>
<td>185.5</td>
<td>173.1</td>
<td>-12.4</td>
</tr>
</tbody>
</table>

All numbers in $ million

Table 1 above shows that the AESO is primarily under-collecting OR costs. The AESO has to carry the resulting shortfall until Rider C recovers this amount. The largest monthly shortfall in each year was $13.8 million in October 2006, $25.8 million in July 2007, and $21.0 million in September 2008. The largest quarterly shortfall in each year was $16 million in the 4th quarter of 2006, $25.7 million in the 3rd quarter of 2007, and $30.6 million in 3rd quarter of 2008.

Figure 1 below presents the information in a graphic form.
3 Cost Drivers

OR cost primarily depends on PP. OR offers are linked to PP and are priced at a discount or premium to the PP. Other factors also affect OR cost, including outages, weather, load, load characteristics, power flows, imports, exports, fuel price, and market participant behavior. These factors are expected to be reflected in large part by the PP.

Analysis of Figure 1 indicates that changes in cost are larger than changes in revenues which suggests the OR charge needs to be a stronger function of PP. Currently, the OR charge varies directly with PP. Figure 2 maps monthly OR cost to monthly average PP using several different functions. The correlation between OR cost and PP varies from $r^2 = 0.8123$ for a linear function, to $r^2 = 0.8126$ for a quadratic function, and to $r^2 = 0.8174$ for a cubic function. These correlations demonstrate that OR cost is strongly influenced by PP.
4 Rate Design

As discussed above, the OR charge needs to a stronger function of PP than the current one. The AESO considers that any revision to the OR charge should be somewhat gradual especially since forecasting PP is quite difficult. Rates that are a stronger function of PP yet not radically different from the current rate include the following.

- On/Off-Peak: $x_1 \times PP$ for 7am-11pm and $x_2 \times PP$ for 11pm-7am
- Block: $x_1 \times PP$ when PP is in block 1 (0-P1) and $x_2 \times PP$ when PP is in block 2 (P1-1000)
- Exponential: $x_1 \times e^{(PP \times x_2)}$
- Linear: $(x_1 \times PP) + x_2$ (current rate is linear with $x_2$ being zero)
- Quadratic: $(x_1 \times PP^2) + (x_2 \times PP) + x_3$
- Power: $x_1 \times PP^{x_2}$
- Block Continuous: $x_1 \times PP$ when PP is in block 1 (0-P1) plus $x_2 \times (PP-P1)$ when PP is in block 2 (P1-1000)
• Block Continuous with Floor: $x1/MWh plus $x2 \times PP$ when PP is in block 1 (0-P1) plus $x3 \times (PP-P1)$ when PP is in block 2 (P1-1000)

For any of the above rates, the OR charge for an hour will be the rate for that hour multiplied by the DTS energy volume for that hour.

5 Criteria
The AESO believes that the possible OR rates should be compared using following criteria:
• Recovery of forecasted annual OR cost
• Minimization of monthly shortfall or surplus
• Sensitivity to PP
• Sensitivity to DTS energy volume
• Simplicity
• Clarity
• Ease of administration

6 Method
To assess each possible OR rate, a rate was first determined using forecasted hourly PP and forecasted annual OR cost so as to minimize the difference between forecasted annual OR cost and annual OR revenue under the rate. For block rates, P1 was taken as the simple average of forecasted PP for the year.

The second step was to compare the monthly root mean square (RMS) variance between actual monthly OR cost and monthly OR revenue under the rates and to examine the sensitivity of monthly RMS variance to PP and DTS energy volume.

The third step was to analyze the three block rates using break points other than average PP. This determined if a break point existed that would further reduce monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

The final step was to fix the ratio of the rates in two blocks. This constrained the solution and simplified it as well. Analysis of the results determined if there is a ratio which further reduces monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

This analysis was repeated for 2006, 2007, and 2008. Results were analyzed to see if any particular combination of block rate, break point, and ratio of the rate in two blocks can work for all three years.

7 RMS Variance
Results show that block rates result in the least RMS variance between actual monthly OR cost and monthly OR revenue under these rates. The Block Continuous rate has the least monthly RMS variance of $4.64, $5.78, and $6.76 million for 2006, 2007, and 2008 respectively.
### Table-2 Monthly RMS Variance

<table>
<thead>
<tr>
<th>Rate</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hourly On/Off-peak</td>
<td>6.37</td>
<td>6.63</td>
<td>7.08</td>
</tr>
<tr>
<td>Block</td>
<td>5.35</td>
<td>6.38</td>
<td>7.18</td>
</tr>
<tr>
<td>Exponential</td>
<td>14.69</td>
<td>12.52</td>
<td>9.67</td>
</tr>
<tr>
<td>Linear</td>
<td>6.29</td>
<td>7.13</td>
<td>7.49</td>
</tr>
<tr>
<td>Quadratic</td>
<td>64.71</td>
<td>25.29</td>
<td>6.65</td>
</tr>
<tr>
<td>Power</td>
<td>14.72</td>
<td>12.56</td>
<td>9.68</td>
</tr>
<tr>
<td>Block Continuous</td>
<td>4.64</td>
<td>5.78</td>
<td>6.76</td>
</tr>
<tr>
<td>Block Continuous with Floor</td>
<td>25.05</td>
<td>5.78</td>
<td>6.76</td>
</tr>
<tr>
<td>Actual</td>
<td>5.83</td>
<td>7.74</td>
<td>10</td>
</tr>
</tbody>
</table>

* P1 was rounded simple average of forecasted hourly PP for the year

### 8 Sensitivity

Block rates are also among the least sensitive to PP and DTS energy volume when measured in terms of change in monthly RMS variance between actual monthly OR cost and monthly OR revenue under these rates.

#### Figure 3

![Sensitivity of Monthly RMS Variance](image-url)
As Figures 3 and 4 show, for 2006, monthly RMS variance varied by about $3 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%. Usually the difference between forecasted and actual PP and DTS energy volume is less than 25% and 5% respectively.
As Figures 5 and 6 show, for 2007, monthly RMS variance varied by about $3.5 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%.

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**Figure 7**

Sensitivity of Monthly RMS Error to Pool Price
As Figures 7 and 8 show, for 2008, monthly RMS variance varied by about $4 million as PP varied by 25% and by about $0.5 million as DTS energy volume varied by 5%.

9 Best Rate for Each Year
Applying the criteria listed in section 5 above, the Block Continuous rate performs best over 2006 to 2008. For 2006, a ratio of two between the rates in two blocks gives the best result (i.e. x2 is two times x1). The resulting monthly RMS variance is about $3.2 million and annual variance is about $20 million. If P1 is chosen as $150/MWh then x1 is 3.62% and x2 is 7.25%. Figure 9 below illustrates the results graphically.
For 2007, a ratio of three between the rates in two blocks gives the best result (i.e. x2 is three times x1). The resulting monthly RMS variance is about $2 million and annual variance is less than $2 million. If P1 is chosen as $150/MWh then x1 is 3.44% and x2 is 10.32%. Figure 10 below shows the monthly RMS variance.
For 2008, a ratio of four between the rates in two blocks gives the best result (i.e. $x_2$ is four times $x_1$). The resulting monthly RMS variance is about $4.8$ million and annual variance is less than $1.5$ million. If $P_1$ is chosen as $150$/MWh then $x_1$ is $2.89\%$ and $x_2$ is $11.57\%$. Figure 11 below shows the monthly RMS variance.

The AESO also studied the Block Continuous rate with three (rather than two) blocks. Increasing the number of blocks from two to three reduces the monthly RMS variance range by $1-2$ million. Given that the optimal ratio for each year is different, that data for only three years is available, and that all three years appear to be significantly different, the AESO favours making gradual changes to the OR rate. Once actual performance of the proposed two block rate is analyzed and additional data becomes available, the AESO will review if a three block rate still provides an improvement and whether the extent of the improvement is worth the additional complexity.

10 Overall Best Rate for Immediate Future

Figures 9, 10, and 11 indicate that $P_1$ can be selected anywhere between $120-180$/MWh without significantly increasing the monthly RMS variance for the year.

As well, the ratio of rates in the two blocks has significant effect on the monthly RMS variance. For 2006, the best performance was obtained at a ratio of two, for 2007 at a ratio of three, and for 2008 at a ratio of four. Thus it is not clear what ratio should be chosen for future years. The AESO considers that years that are expected to be similar to the immediate future years should be given more weight. To understand differences between 2006, 2007, and 2008, the AESO
looked at the underlying data and events to gain further insight. Table 3 summarizes some factors that may have caused results to differ.

Forecasted and actual PP were quite close for 2007 and 2008 but were under-forecasted in 2006. Standard deviation of actual PP is stable while that of forecasted PP is increasing and getting closer to the actual. Standard deviation of forecasted DTS energy volume is stable and is close to the actual except for 2006 when the actual was significantly lower. Standard deviation of the product of actual DTS energy volume and actual PP is quite stable while the comparable forecasted amount is increasing and getting closer to the actual. The 2009 PP forecast is similar to that of 2008, the standard deviation of 2009 forecasted PP is close to that of 2007, and the standard deviation of the product of 2009 forecasted DTS energy volume and forecasted PP is close to that of 2007. The last two rows of the table show that annual OR cost has been consistently under-forecasted.

The natural gas price (AESO-C) varied from $4.45 to $8.16 per mmBtu in 2006, from $4.70 to $7.49 per mmBtu in 2007, and from $5.85 to 10.60 per mmBtu in 2008. As figure 12 shows, in 2008, natural gas prices increased in the first half of the year and then fell in the second half. This trend is quite different from what went on in 2006 and 2007. The 2009 prices to date have been much lower than any of 2006-2008.
The AESO, the sole buyer of OR, began purchasing a majority of OR on a day ahead basis since May 2008. Prior to May 2008, AESO purchased OR anywhere from five days ahead to one day ahead.

Another significant difference may be the actual availability of Power Purchase Agreement (PPA) units, which was 88% in 2008 compared to 91% in 2006 and 2007 on a PPA-weighted average basis.

Because of the recent economic downturn, the Pool Price and thus the OR cost in 2009 is expected to be lower than in 2008. Also, the approval and future implementation of WECC BAL-002 standard is expected to reduce OR requirements somewhat thus possibly reducing OR volumes. The AESO Budget Review Process (BRP) resulted in approval of the 2009 forecast reflecting a simple average 2009 forecasted PP of $84.43/MWh, a volume-weighted average 2009 forecasted PP at $86.88/MWh, and a forecast 2009 annual OR cost of $235.5 million. The AESO considers that using the AESO Board approved forecast is reasonable, and does not propose to use later forecast information that has not been subject to such approval. However, new information can be taken into account when selecting the best overall rate. In the AESO’s opinion, it appears that 2009 and perhaps 2010 could be closer to 2007 and 2006 rather than 2008 with respect to characteristics that might be relevant to the OR charge design.
11 Selection
This section compares monthly RMS variance for a ratio of rates in the two blocks at 2, 2.5, and 3 with P1 varying from $120-180/MWh.
Figures 13, 14, and 15 show that for a ratio of two, the maximum monthly RMS variance is between $7.7 million and -$3.8 million for 2006, between $2.2 million and -$10.9 million for 2007, and between $6.3 million and -$12.4 million for 2008.
Figures 16, 17 and 18 show that for a ratio of 2.5, the monthly RMS variance is between $8.3 million and -$0.4 million for 2006, between $2.2 million and -$5.5 million for 2007, and between $6.6 million and -$10.9 million for 2008.
Figure 19

Difference between actual cost and projected revenue - 2006

Figure 20

Difference between actual cost and projected revenue - 2007
Figures 19, 20, and 21 show that for a ratio of three, the monthly RMS variance is between $13.3 million and $0.2 million for 2006, between $3.1 million and -$4.2 million for 2007, and between $6.9 million and -$9.6 million for 2008.

These observations are summarized in Table 4 below. The average of maximum monthly RMS variance, average of average monthly RMS variance, and average of absolute average of monthly RMS variance increase as the ratio increases, while the average of minimum monthly RMS variance and the range (i.e. difference between maximum and minimum monthly RMS variance) decrease as the ratio increases. It appears that a ratio of 2.5 works best overall.

Table 4 – Monthly Variance Using Different Ratio

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Variance</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>Average Variance 2006-08</th>
<th>Absolute Average Variance 2006-08</th>
<th>Range 2006-08</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Maximum</td>
<td>7.68</td>
<td>2.25</td>
<td>6.32</td>
<td>5.42</td>
<td>5.42</td>
<td>18.71</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>-3.81</td>
<td>-10.88</td>
<td>-12.39</td>
<td>-9.03</td>
<td>9.03</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>1.74</td>
<td>-1.01</td>
<td>-1.73</td>
<td>-0.33</td>
<td>1.49</td>
<td></td>
</tr>
<tr>
<td>2.5</td>
<td>Maximum</td>
<td>8.32</td>
<td>2.18</td>
<td>6.64</td>
<td>5.71</td>
<td>5.71</td>
<td>17.53</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>-0.36</td>
<td>-5.53</td>
<td>-10.89</td>
<td>-5.59</td>
<td>5.59</td>
<td></td>
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<tr>
<td></td>
<td>Average</td>
<td>3.44</td>
<td>-0.45</td>
<td>-1.19</td>
<td>0.60</td>
<td>1.69</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Maximum</td>
<td>13.29</td>
<td>3.06</td>
<td>6.91</td>
<td>7.75</td>
<td>7.75</td>
<td>16.54</td>
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<tr>
<td></td>
<td>Minimum</td>
<td>0.22</td>
<td>-4.19</td>
<td>-9.63</td>
<td>-4.53</td>
<td>4.68</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>5.11</td>
<td>0.06</td>
<td>-0.73</td>
<td>1.48</td>
<td>1.97</td>
<td></td>
</tr>
</tbody>
</table>

All numbers in $ million
12 Performance

Figures 22, 23, and 24 show the monthly maximum, average, and minimum RMS surplus/shortfall for 2006, 2007, and 2008 respectively with P1 being varied from $120-180/MWh and x2 being 2.5 times x1. It is clear that the proposed rate is an improvement over the currently approved rate, which is included and labeled as “Actual” in the figures.
Figure 24

2008 Monthly Variance

Figure 25 graphs actual OR cost, actual OR revenue (under the currently approved rate), and OR revenue that would have occurred under the proposed rate design for the years 2006-2008. This again illustrates that the proposed rate tracks actual OR cost better.

Figure 25

(2006-08 Monthly OR Cost and Revenue Limited Edition)
13 Proposed Rate

As discussed above, for 2009, a Block Continuous OR charge with P1 as $150/MWh and x2 as 2.5 times x1 would better match OR cost and revenue. For that rate design for 2009, x1 would be 4.47% and x2 would be 11.18%. Figure 26 below shows the proposed rate in graphical form. Other P1 series are included for illustrative purposes.

Figure 26

![Graph of Proposed 2009 OR Rate](image)

Figure 27 below shows the corresponding OR charge in $/MWh that would result.

Figure 27

![Graph of 2009 Proposed Operating Reserve Charge ($/MWh)](image)
14 Discussion

Bill impact for an individual customer under the proposed rate would depend on the customer’s load profile and could be calculated using forecasted hourly PP and forecasted hourly DTS volume.

The AESO will continue to monitor the trends in and relations of OR cost and will study further alternatives to better match OR cost and OR revenue to reduce the variance even further.

The AESO will also investigate the possibility of implementing systems and processes to record, allocate, and bill OR cost on an hourly basis. Questions for an hourly allocation approach include whether OR cost should be divided into constituent categories and if different billing determinants should be used for the constituent categories. Since this approach will recover OR cost on an hourly basis, it should practically eliminate any over or under collection.
May 30, 2009

Fort Nelson Rate FTS Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Fort Nelson Rate FTS Working Group

The first meeting of the Fort Nelson Rate FTS Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 2:00 to 4:00 PM
- **Date:** Monday, June 1, 2009
- **Location:** Meeting Room 2538, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, and soft drinks

This working group includes the following members:
- AltaLink: Hao Liu
- BC Hydro: John Rich, Yvette Maiangowi, Fred James, or Lewis Manning
- Harvest: Dale Hildebrand
- IPCAA: Sheldon Fulton
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   - 2:00 PM

2. **Review agenda**
   - 2:10 PM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
     - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
   - 2:15 PM
A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

### Background for Fort Nelson Rate FTS

2:20 PM

- Please review the enclosed information before the meeting, if possible:
  1. History of service to Fort Nelson from 1990 to 2000, as summarized by BC Hydro in Exhibit “B” of its evidence in the AESO’s 2005-2006 General Tariff Application proceeding, filed on March 11, 2005
  2. Discussion of the Fort Nelson rate in section 5.7 (pages 30-33) of Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
  4. Section 5 (Electricity Supply and Relevant Market Forecasts) and section 6 (Planning Horizon Resource Options) of the Fort Nelson Appendix N1 to BC Hydro’s 2008 Long Term Acquisition Plan as updated on October 24, 2008 (available in its entirety on www.bcuc.com by following the path Current Applications ▶ BC Hydro - 2008 LTAP ▶ B-1-10, in the “Exhibits” section)

- Is there other background that participants consider particularly relevant?

### Scope for Fort Nelson Rate FTS Working Group

2:30 PM

- Long-term load considerations in the Rainbow Area (including Fort Nelson)
- AESO obligations with respect to service to Fort Nelson
- Impacts of service to Fort Nelson with respect to:
  - TFO (capital and operating) costs,
  - ancillary services (TMR) costs, and
  - pool price
- Rate design principles for service to Fort Nelson
- Specific features of Fort Nelson Rate FTS to be proposed in AESO’s 2010 tariff
- Working group will not review or discuss Interim Refundable Fort Nelson Rider H, as the intent is to develop a principle-based and sustainable replacement for that rider

### AESO obligations with respect to service to Fort Nelson

2:45 PM

- The Electric Utilities Act requires the AESO to plan the transmission system to meet the needs of Alberta (as expressed in sections 33 and 34(1), for example)
- The rate charged to BC Hydro at Fort Nelson must be just and reasonable
  - How should justness and reasonableness be assessed?

### Impacts of service to Fort Nelson

3:15 PM

- TFO (capital and operating) costs
- Ancillary services (TMR) costs
- Pool price, including Dispatch Down Service (DDS) impacts
Follow-up required for next meeting 3:50 PM

- Summarize what tasks need to be completed before next meeting and who will complete them

Dates and times for next meeting(s) 3:55 PM

Adjourn 4:00 PM

This agenda and all other printed information related to the Fort Nelson Rate FTS Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AESC 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
   - Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
Exhibit “B”

Historic service to Fort Nelson can be summarized as follows:

- Pre-1991, Fort Nelson, B.C. was served by BC Hydro through a non-integrated distribution system with power generated by a diesel generating station.
- May 1990 – Wescup agreed to construct/own and operate transmission facilities in B.C. to permit the sale and delivery of electric energy by Wescup to BC Hydro.
  - APL built and Wescup paid for and was owner of the BC facilities (105 km long at a cost of 15.6 million).
- May 1990 – APL entered into an electricity sale agreement with Wescup to supply electricity from the Alberta interconnected electric system to Wescup for resale to BC Hydro (the “ESA”). Energy was supplied on an interruptible basis. The term of the ESA was 20 years.
- November 1990 – The Energy Resources Conservation Board approved the interconnection of APL facilities with the Wescup facilities.
- 1991 – APL constructed the interconnection facilities in Alberta (65 km long at a cost of $4.3 million).
  - Wescup paid a capital contribution towards the construction of the Alberta facilities of $782,000.
  - December 1991 - In Decision E91095, the Board found that since Wescup effectively took delivery of electric energy in Alberta, it was an Alberta customer.
- May 1993 - In Decision E93035, the Board approved APL’s proposal to charge a special facilities charge to Wescup through a rate rider (“Rider E”). The facilities charge was approved on the basis that it was consistent with treatment of other APL customers assessed a special facilities charge.
- 1999 – the Board approved the sale by Wescup of its system to BC Hydro.
- 1999 – the Board approved ATCO Electric’s GTA, including the flow-through of the TA’s opportunity service to BC Hydro and Rider E (the facilities charge). Service continued to be supplied on an interruptible basis.
- 2000 – Trans Alta Energy constructed a gas fired generating station near Fort Nelson. BC Hydro contracted to buy all of the energy from the generating station. BC Hydro still required back up for its load at Fort Nelson. After being told by ATCO Electric that it would not provide firm back-up service to BC Hydro, BC Hydro made inquiries of the TA about receiving firm service directly.
- July 2000 – ATCO Electric and AESO concluded an agreement to allow the TA to provide a firm back-up service directly to BC Hydro.
The Board agrees with the AESO that the proposed reduction in ratchet term to two years provides a reasonable balance between customer flexibility and revenue stability. The AESO’s proposal is therefore approved, subject to the direction contained above that no ratchet will apply to bulk wires costs.

5.5.4 Standby Tariffs

The Application did not contain a specific proposal for a standby rate. The AESO noted that it had commenced discussions with customers with respect to the development of such a rate and suggested that a standby rate may offer some relief to the low load factor customers most impacted by changes to the DTS rate. The AESO proposed to engage in additional customer consultation on rate design immediately after the decision on its 2006 tariff application is issued in preparation for filing its 2007 application.

The Board notes that EnCana and TransAlta supported the development of rates for low load factor or standby customers, and were specifically supportive of the discussion of such a rate in consultations proposed by the AESO for its 2007 tariff. ADC and IPCAA also supported the development of such a rate as a means to ameliorate the effect of their DTS rate proposals.

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. The Board has no specific directions with respect to stand-by rates, however.

5.6 Supply Transmission Service Rate (STS)

The Board notes that the AESO did not specifically comment upon the design of the STS rate in Section 4 of the Application nor did any party comment upon it in argument or reply.

The Board notes that the Transmission Regulation has had the effect of shifting all wires costs to load. The only significant cost left for supply customers is line losses. This has been appropriately reflected in the design of the STS rate proposed in Section 7 of the Application. The rate is approved as filed.

5.7 Fort Nelson BC Rate

The AESO explained its rate proposal respecting its proposed Fort Nelson Demand Service (FDS) Rate as follows:

The AESO has examined the Fort Nelson arrangement in light of its history and current circumstances, and has decided to not re-apply for the approval of the Fort Nelson Settlement. Instead the AESO has determined that the treatment of BC Hydro and Powerex under DTS and STS contracts respectively as set out in the Settlement is inappropriate for the following reasons:

(a) Current DTS and STS rates are intended for service to Alberta customers. BC Hydro and Powerex are not Alberta customers.

(b) The current DTS contract does not appropriately reflect the type of services provided to BC Hydro and Powerex, nor does it reflect the principles set out by
the EUB in Decision E91095 to recover the incremental cost burden to Alberta so that Albertans do not subsidize BC through serving Fort Nelson.

(c) The provision of ancillary services (especially transmission must run, or TMR, services) as well as the treatment of losses has developed well beyond the levels that existed at the time the original Fort Nelson Settlement was entered into in July 2000.

The AESO therefore proposes to terminate the DTS contract with BC Hydro and replace it with a load contract for a specific Fort Nelson Demand Transmission Service (FDS) rate, and to terminate the STS contract with Powerex and replace it with an import opportunity contract under the standard IOS rate. The FDS rate is intended to recover the costs associated with the demand services provided to Fort Nelson, while the IOS rate will recover the costs associated with the import services provided.49

The AESO proposes to charge Fort Nelson a customized DTS rate and an Import Opportunity Service (IOS) rate that would include:

(i) the forecast cost to be incurred by ATCO Electric to supply the transmission line to Fort Nelson;
(ii) a transmission must run (TMR) cost that is based upon TMR dispatched from Fort Nelson and standby TMR from Alberta;
(iii) the losses attributable to the Fort Nelson generator; and
(iv) the charges to recover general and administrative costs attributable to Fort Nelson.

The largest charge would be the TMR costs which were forecast to be $6 million for 2006.

In argument, the AESO continued to maintain that Fort Nelson was not eligible for the postage stamp DTS rate, arguing that it did not fall under Subsection 30(3) of the Electrical Utilities Act (EUA) and that the FDS rate fairly reflected the cost of providing service to Fort Nelson. The AESO also argued that the large increase in costs to Fort Nelson did not constitute rate shock as it would only increase British Columbia Hydro and Power Authority’s (BCH) total costs by 0.25%. In reply, the AESO did not dispute that it had an obligation to serve the Fort Nelson load, but maintained it had a corresponding responsibility to recover the costs of such service. FIRM supported the AESO’s argument.

In its intervener evidence, BC Hydro (BCH) strongly opposed the AESO’s proposal, stating that it was discriminatory, unfair and failed to consider value of service. BCH noted that its costs would rise by approximately 2800%, an increase constituting rate shock of a magnitude imposed upon no other DTS customer. BCH maintained that it had historically been treated as an Alberta customer and stated as such it should continue to receive non-discriminatory access to the same postage stamp DTS and STS service as any other Alberta customer, regardless of the estimated individual incremental cost.

In argument, BCH stated that the AESO had an obligation to continue to serve Fort Nelson and such service should be provided under the DTS rate. BCH maintained that the AESO had presented no evidence that the EUA allowed it to discriminate against customers such as Fort Nelson due to its location. In the event that Fort Nelson was determined by the Board to not qualify as an Alberta customer eligible for the DTS rate, BCH submitted that service should be

49 Application. Section 4, page 19
provided on an incremental cost basis, which it described as inherently unstable and difficult to calculate. In particular BCH stated:\footnote{BCH argument, page 8}

As Mr. Stout made clear\footnote{Transcript Volume 7 at page 1678, line 6 to page 1679, line 16; see also Transcript Volume 7 at page 1719, line 5 to page 1722, line 22.}, if the AESO wants to ignore BC Hydro’s status as a customer on the basis that the ultimate load is outside Alberta, then, logically, it must look at the total consequence of the service provided to and obtained from the territory it has determined to be foreign. In other words, if it wishes to employ an incremental analysis, it must look at the incremental effect of Fort Nelson generation, as well as Fort Nelson load. If that is done, there can be no doubt that the relative efficiency of the Fort Nelson generation introduces a substantial benefit to the Rainbow Lake area and significantly diminishes the cost of providing transmission must run ("TMR") within that area of northwest Alberta.

The AESO’s calculation of the costs of serving Fort Nelson load significantly exaggerates the actual incremental cost of serving by inappropriately combining a calculation of some embedded historical costs with a flawed calculation of gross incremental costs of service to serve the Rainbow Lake area.

Specifically, the AESO has included in what it calls incremental costs, wires costs that are not incremental in any normal sense of that word’s use in cost studies.\footnote{Transcript Volume 7, page 1682, lines 7-13.} As Mr. Stout testified, these costs represent a non-averaged wires cost directly allocated to Fort Nelson but not to any other radial line customer.\footnote{Transcript Volume 7, page 1702, line 17 to page 1703 line 13.} In addition, the AESO has also declared the $455,000 contribution towards fixed costs to be an incremental cost of serving Fort Nelson, and yet admits that such contribution towards fixed costs would simply be reallocated to other Alberta load in the event that Fort Nelson were no longer integrated with the AESO system.\footnote{See Exhibit 02-020 at BCH.AESO-006(a).} This contribution, like the wires costs, forms no proper part of an incremental cost study because they are sunk or embedded costs which would remain even if the Fort Nelson load were no longer present. A truly incrementally-based rate would not include these costs.

The Board rejects BCH’s argument that it should continue to receive service under the DTS rate. The Board cannot ignore the obvious – Fort Nelson is not located in Alberta. As such, the Board does not consider that the AESO is obliged to offer the postage stamp service that it is obligated to provide to Alberta customers.

Equally, however, the Board considers that the rate charged to BCH for Fort Nelson service must be just and reasonable, in accordance with established regulatory principles. The Board does not consider that the proposed FDS rate conforms to these principles. The Board also believes that the rate charged for Fort Nelson service must be designed in such a manner that it will provide a fair and reasonable template that can be used in determining rates for other inter-provincial service, be it service provided by the AESO to other BC customers or by BCH to customers located in Alberta. The Board does not consider the AESO’s proposal to be either just or reasonable.
The Board notes that the largest single element in the proposed FDS rate is the allocation of TMR costs. The Board agrees with BCH that the AESO has not provided a sufficient basis for this charge. In particular, the Board does not consider that there is sufficient evidence that the AESO has considered the real value of Fort Nelson generation to Alberta customers.

The Board also notes the proposed $455,000 charge for contribution to fixed costs. The Board does not consider this charge has been justified on the basis of a reasonable allocation of actual costs.

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. the postage stamp rate for bulk wires costs;
2. the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;
3. the postage stamp rate for the AESO’s own costs and other industry costs; and
4. the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.

The Board does not consider it necessary to charge a POD related cost as BCH provides its own facilities. Correspondingly, BCH should not be eligible for the PSC credit in the future as it will not be charged for POD services.

The STS service provided to Fort Nelson should continue to be charged at the full postage stamp rate plus a losses charge to be determined by the AESO, in the same manner as it would for an Alberta generator.

Both DTS and STS services provided to Fort Nelson should continue to be subject to the usual deferral account treatment, similar to that of any other customer.

The Board considers the above will result in just and reasonable charges for service to Fort Nelson. The Board also considers that this provides a reasonable template for the provision of other inter-provincial services as well. The AESO’s proposed tariff treatment of Fort Nelson is denied and the AESO is directed to continue to provide DTS and STS services to Fort Nelson on the basis set out above and the refiling should demonstrate this treatment.

5.8 Export Rates

5.8.1 Firm Export/Import Rates

In Decision 2002-099, the Transmission Administrator’s (TA) Congestion Management Decision, the Board directed the TA to “…further investigate whether a firm import/export service could be offered over the existing B.C. Tie with a level of “firmness” acceptable to prospective import/export customers”.

In response to this directive, the AESO submitted that it began contacting its customers active in importing and exporting in the spring and summer of 2004. On September 23, 2004, the AESO published an Alberta Import/Export Tariff discussion paper to broaden consultation with stakeholders. The paper was presented at a stakeholder conference on October 6, 2004 followed by written comments from six stakeholders. Discussion was also held at a December 3, 2004
4.2.1 Detailed Description of the Concepts

a) Concept 2 (Preferred Concept)

Concept 2 is a full transmission concept and when Phase 1 is completed in 2009, the Rainbow Lake area will not rely on any TMR generation. The component additions recommended in this concept can be staged into two phases, Phase 1 (2007 & 2009) and Phase 2 (2014).

2007 Additions:

Shunt capacitors are proposed at Goodfare 815S and Big Mountain 845S in the Grande Prairie area to maintain the system voltages during normal and contingency conditions. Shunt capacitors are also proposed at Ksituan River 754S and Friedenstal 800S to provide reactive power support. A Static VAR Compensator (SVC) at Cranberry Lake (827S) is also proposed to provide dynamic VAR support to 7L61, 7L63 and 7L12. Shunt capacitors are also proposed at Lubicon 780S and Little Smoky 813S. The proposed reactive power support in the Grande Prairie and Peace River areas prevents the voltage collapse in Area B under the contingency of Poplar Hill unit (refer to Row 3 of Table 3.1-1) as well as Need Identification Results, Volume II.

The need studies have shown the requirement of the second transformer (Table A2, Figure A-2K in Need Identification Results, Volume II). ATCO Electric has a spare 240/144 kV 120/160/200 MVA transformer available at Louise Creek 809S. It is therefore recommended that this transformer should be put in service at Louise Creek 809S by 2007.

2009 Additions:

A 240 kV Brintnell 876S to Wesley Creek 834S line is proposed to bring power from Fort McMurray area to the Northwest. This transmission line provides strong voltage support at Wesley Creek 834S which now acts as a sending node for power to Rainbow Lake and High Level areas. With the addition of this 240 kV line, the outage of 9L11 Little Smoky 813S to Wesley Creek 834S is no longer a critical contingency. A 144 kV double circuit from Wesley Creek 834S to Hotchkiss 788S provides capacity as well as reliability to the system north of Wesley Creek.

In the Rainbow Lake and High Level areas, a 144 kV line is proposed from Ring Creek 853S to Rainbow Lake 791S and another line is
proposed from Sulphur Point 828S to High Level 786S. This will result in Rainbow Lake-Ring Creek-Keg River and Keg River-High Level- Sulphur Point 144 kV closed loops. In the absence of generation in the Rainbow Lake area, the closing of the High Level 786S to Sulphur Point 829S and Ring Creek 853S to Rainbow Lake 791S 144 kV loop helps in providing voltage support and also provides capacity during contingency conditions. The removal of generation from the Rainbow Lake and Fort Nelson areas will result in low short circuit levels in the area. For this reason, a synchronous condenser is recommended in the Rainbow Lake area to provide reactive power support as well as improve the short circuit levels. A SVC at High Level 786S will provide voltage control under normal and contingency conditions.

The 919L and 989L Sundance to Sagitawah 240 kV lines provide power from the Wabamun area into the Northwest region. In the 2009/10 scenario and beyond, the loading on each of these two circuits will increase to well over 300 MW. Therefore, a SVC at Little Smoky 732S is proposed to maintain voltages during contingencies of 919L, 989L or the proposed 240 kV Brindnell to Wesley Creek line.

This development in the Rainbow Lake and High Level areas along with the Brindnell 876S to Wesley Creek 834S to Hotchkiss 788S lines will address the need in Area A as mentioned in Section 3.0. The Brindnell 876S to Wesley Creek 834S 240 kV line also helps in deferring the need in Area C from 2011/12 (refer to Row 7 in Table 3.1-1) to 2014. The proposed development also eliminates the use of TMR from the Rainbow Lake area. However, the AESO will continue to maintain the long term TMR contracts in the Grande Prairie and Valleyview areas in order to provide only reactive power support.

**2014 Additions:**

A 240 kV line from Bickerdike 39S to Little Smoky 813S is proposed to provide the additional feed into the Northwest region as the proposed Brindnell 876S to Wesley Creek 834S line will not be adequate in the longer term to meet the load in the southern part of the region. This new line will provide relief to 989L and 919L by reducing the loading on these two circuits thus improving the voltage stability limit identified earlier.

b) Other Full Transmission Concepts Considered

**Concept 1**

Concept 1 is similar to Concept 2 except in the Rainbow Lake and High Level areas where a single circuit 144 kV line is proposed from
Details regarding the multiple variable analysis and methodology are provided in Appendix G and the Alternative Assessment Methodology, Volume II, respectively.

c) Impact of Changing System Conditions

As previously noted, the AESO has based its recommendation primarily on the non-financial benefits that Concept 2 provides over the other concepts and has considered the financial results in balance with these other benefits. The base financial results indicate that the relative loss benefits are a significant factor in determining the total net benefit of the concepts. The base analysis indicates that Concepts 1 and 3 are more favorable in total than Concept 2 primarily due to the loss benefits. Conversely, Concept 4 shows less favorable results than Concept 2 due to the cost of losses.

Due to this reliance on loss benefits and costs to render the other concepts more or less favorable than Concept 2 the AESO has performed the following analysis to test the sensitivity of these benefits under changing system conditions that may affect the Northwest.

The following analysis has been based on a more simplified calculation. For this purpose the winter peak load losses for the complete Alberta system were multiplied by the square of the load factor of the system which was considered to be 0.79 to calculate the approximate average system losses for the whole year. This approach was adopted to expedite the calculation of the losses for the purpose of this specific analysis.

i) Changing Load in the Rainbow Lake Area

The AESO has tested the sensitivity of loss benefits in relation to changes in load in the Rainbow Lake area. Specifically, this includes the potential decline of the Husky processing plant load (35 MW) and of the Fort Nelson, BC load (25 MW).

Husky has informed the AESO that its load located at Rainbow Lake will start to decline after the 2010 timeframe. The AESO confirmed this independently through a report, referred to as the Stantec Report, which it published on the AESO website in August 2005. For further information regarding this report, please refer to Appendix C.

Similarly the load at Fort Nelson, BC may change in the event that BC Hydro decides to serve this load through some internal means (generation, transmission, etc.) rather than from Alberta. The AESO has assumed Fort Nelson as a firm load in its base analysis as it is
obligated to serve Fort Nelson under the DTS contract with BC Hydro. It is important to note that in discussions with BC Hydro, the AESO has not had any indications about the decline of Fort Nelson load.

The following analysis shows the impact on the concepts with no load at the Husky processing plant or at Fort Nelson, BC.

Table 5.2.5-3: Base Analysis: With Fort Nelson & Husky Load - Better Than (Worse Than) Concept 2

<table>
<thead>
<tr>
<th>20-Year PV</th>
<th>Concept 1</th>
<th>Concept 2 (Preferred Concept)</th>
<th>Concept 3</th>
<th>Concept 4</th>
<th>Concept 2H</th>
<th>Concept 3H</th>
<th>Concept 4H</th>
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<tr>
<td>Wires</td>
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<tr>
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<td>($19M)</td>
<td>$22M</td>
<td>$98M</td>
<td>$14M</td>
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<tr>
<td>TMR</td>
<td>$0M</td>
<td>$0M</td>
<td>$0M</td>
<td>$0M</td>
<td>($68M)</td>
<td>($68M)</td>
<td>($68M)</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$41M</td>
<td>$0M</td>
<td>$23M</td>
<td>($13M)</td>
<td>($11M)</td>
<td>($5M)</td>
<td>($13M)</td>
</tr>
</tbody>
</table>

Table 5.2.5-4: Scenario: Fort Nelson & Husky Load Removed - Better Than (Worse Than) Concept 2

<table>
<thead>
<tr>
<th>20-Year PV</th>
<th>Concept 1</th>
<th>Concept 2 (Preferred Concept)</th>
<th>Concept 3</th>
<th>Concept 4</th>
<th>Concept 2H</th>
<th>Concept 3H</th>
<th>Concept 4H</th>
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</thead>
<tbody>
<tr>
<td>Wires</td>
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<tr>
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<td>($16M)</td>
<td>$9M</td>
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<td>$3M</td>
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<td>$0M</td>
<td>$0M</td>
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<td>($24M)</td>
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</table>

To be expected, the most significant impact of this load reduction in the Rainbow Lake area is to Concept 1. The loss benefits of Concept 1 are reduced substantially in relation to Concept 2 with the Husky and Fort Nelson loads removed. Similarly, the loss benefits in Concept 3 are also reduced bringing the total result compared to Concept 2 slightly worse off. Finally, with respect to Concept 4, the cost of losses is reduced given that the loss of load from the Rainbow Lake area
would lessen the pressure from the Wabamun / Edmonton generation source.

ii) Fort Nelson Generation

Although the AESO has assumed Fort Nelson load in its base analysis due to contractual obligations, BC may decide to continue operation of the Fort Nelson generator. The following analysis shows the impact on the concepts of continued generation at Fort Nelson supplying the Rainbow Lake area.

**Table 5.2.5-5: Base Analysis: Without Fort Nelson Generation - Better Than (Worse Than) Concept 2**

<table>
<thead>
<tr>
<th>20-Year PV</th>
<th>Concept 1</th>
<th>Concept 2 (Preferred Concept)</th>
<th>Concept 3</th>
<th>Concept 4</th>
<th>Concept 2H</th>
<th>Concept 3H</th>
<th>Concept 4H</th>
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<td>($19M)</td>
<td>$22M</td>
<td>$98M</td>
<td>$14M</td>
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<tr>
<td>TMR</td>
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<td>$0M</td>
<td>$0M</td>
<td>($68M)</td>
<td>($68M)</td>
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<tr>
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<td>$23M</td>
<td>($13M)</td>
<td>($11M)</td>
<td>($5M)</td>
<td>($13M)</td>
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</table>

**Table 5.2.5-6: Scenario: With Fort Nelson Generation - Better Than (Worse Than) Concept 2**

<table>
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<tr>
<th>20-Year PV</th>
<th>Concept 1</th>
<th>Concept 2 (Preferred Concept)</th>
<th>Concept 3</th>
<th>Concept 4</th>
<th>Concept 2H</th>
<th>Concept 3H</th>
<th>Concept 4H</th>
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</thead>
<tbody>
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<td>Wires</td>
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<td>$0M</td>
<td>($31M)</td>
<td>$6M</td>
<td>$35M</td>
<td>($25M)</td>
<td>$41M</td>
</tr>
<tr>
<td>Losses</td>
<td>$15M</td>
<td>$0M</td>
<td>$34M</td>
<td>($17M)</td>
<td>$14M</td>
<td>$62M</td>
<td>$12M</td>
</tr>
<tr>
<td>TMR</td>
<td>$0M</td>
<td>$0M</td>
<td>$0M</td>
<td>$0M</td>
<td>($68M)</td>
<td>($68M)</td>
<td>($68M)</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$13M</td>
<td>$0M</td>
<td>$3M</td>
<td>($11M)</td>
<td>($19M)</td>
<td>($31M)</td>
<td>($15M)</td>
</tr>
</tbody>
</table>

The effect of continued generation from the Fort Nelson plant is similar to that of the loss of load at Husky and Fort Nelson. Again, Concept 2 maintains its benefits in relation to the other concepts.
Possible impacts of future GHG offset costs are analyzed. The GHG emissions of any Fort Nelson gas-fired generation in the analysis are tracked and the volume of carbon dioxide equivalent (CO$_2$e) is measured and the forecast cost of GHG offsets is calculated.

The level of CO$_2$e associated with imports is calculated. Risk analysis is provided with respect to the possible impact of any B.C. Government requirement to offset any GHG emissions that would have been created in Alberta with respect to imported energy to B.C. at Fort Nelson.

4 Stakeholder and First Nations Engagement

With respect to First Nation and stakeholder engagement, refer to Appendix N2 (Exhibit B-1-10).

5 Electric Supply and Relevant Market Forecasts

5.1 Load forecast of BC Hydro Domestic Customers

The Fort Nelson region, as well as the AIES, are generally supplied by thermal generating resources and are capacity constrained and not energy constrained. The combined region of Fort Nelson and Rainbow Lake is also transmission constrained both internally and externally to the AIES.

Therefore, the predominant forecast for reliability planning purposes is the peak demand forecast. The primary use of the energy demand forecast is to calculate the forecast cost of service, including local supply, imports and exports.

The 2007 Reference Load Forecast and Scenarios identify a medium- to long-term customer load growth potential for up to an additional 60 MW to 70 MW by 2013. This represents an approximately 200 per cent increase from the current firm supply capability of 28.5 MW. This load growth is being driven by the development of new industries, primarily in the oil and gas sector. Much of the new load is load that the potential customers could meet by either gas or electric drive systems.
The load growth is expected to come from a relatively small number of commercial or industrial customers. As a result, the actual names and locations of the facilities and the timing of the new or upgraded facilities are commercially sensitive. This, along with the size of the expected increases relative to the size of the base domestic load, has led BC Hydro to conclude that the best manner of presenting and analysing the various new supply solutions (portfolios) is through the use of load growth Scenarios. To that end, BC Hydro is basing its analysis on its 2007 Load Forecast (Reference Forecast) along with three scenarios of possible load growth. Each of the Scenarios has been developed using a bottom-up forecasting methodology based on information gathered, in confidence, from potential customers and assessed by BC Hydro as to the likelihood of the projects proceeding.

BC Hydro formulated three potential load growth Scenarios based on discussions conducted in 2007 with several B.C. oil and gas development companies, or their competitors, and rough projections of future development in the sector.

The Low Scenario was comprised of: (a) the Reference Forecast increased by 1 MW to reflect one or two small projects based on recent land tenure sales; and (b) potential load from six projects, each smaller than 5 MW, estimated by oil and gas developers from potential projects.

Similarly, the Mid Scenario was comprised of: (a) the Reference Forecast increased by approximately 6 MW, to reflect one large generic project; and (b) potential load from a few large projects, each greater than 5 MW, estimated by oil and gas developers from potential projects.

The High Scenario was a compilation of the Reference Forecast, plus the incremental loads described above for the Low and Mid Scenarios.

Subsequent to the preparation of this Reference Forecast and growth Scenarios, two significant customer-related events have occurred:

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10 BC Hydro’s 2007 Load Forecast is presented in Chapter 2 of the 2008 LTAP (Exhibit B-1), with the full BC Hydro 2007 Load Forecast provided in the 2008 LTAP Appendix D (Exhibit B-1-1). The Fort Nelson load forecast is provided in Tables 9.2 and 9.3 of the BC Hydro 2007 Load Forecast.
• The two Canfor mill indefinite closures were announced. One or both mills may come back to service some time in the future, depending on market conditions and Canfor’s future decisions.

• BC Hydro obtained interruptible service from the AESO to serve Harvest Energy’s requested 10 MW of new service. There is not currently sufficient supply to meet this additional load so it is being served by BC Hydro through an AESO interim tariff approved by the AUC that provides for BC Hydro to pay (on an interim refundable basis) 50 per cent of any incremental TMR cost that may be incurred in serving this load. In addition the Harvest Energy load is curtailable in accordance with AESO operating procedures. As of October 24, 2008, the load has been curtailed ten times in 2008.

The following Figure 5-1 and Figure 5-2 present the load forecast scenarios. The Figures that are based on annual capacity or annual peak demand in the FN RP/LTAP are presented in calendar year terms, associated with an assumed December winter peak demand (the fiscal year peak for any one year is assumed to be the calendar year peak for the previous year, for example F2010 peak demand is assumed equal to the 2009 calendar year peak). The energy Figures are presented in fiscal years, linking back to the BC Hydro Load Forecast.
Figure 5-1  Fort Nelson Region Peak Demand Forecast (before DSM)

Figure 5-2  Fort Nelson Region Annual Energy Demand Forecast (before DSM)
5.2 Monthly Load Shapes

The monthly heavy load hour (HLH) and light load hour (LLH) forecasts have been developed for the Reference Forecast and the three Scenarios. These load shapes, set out in section 11, are used in the economic analysis.

5.3 Possible new load in the region

Subsequent to completing the portfolio analysis, BC Hydro received a request for 8 MW that is not in the Reference forecast or in the Scenarios.

BC Hydro has also received indications of additional new loads in the Fort Nelson region. This includes possible new loads in the vicinity of Fort Nelson such as possible developments in the Horn River basin some 70 km north of Fort Nelson. These possible new loads could add 100 MW or more to the Scenarios. A map depicting the location of the Horn River basin is attached as Attachment 1 to this Appendix N1.

Given the new load is associated with the development of new natural gas supply, it is uncertain at this time how much of the load would be served by BC Hydro. Parties developing the gas resources may choose to use gas drives or install their own self-generation facilities to meet some or all of their electricity requirements.

As a result of having load that must be served on an interruptible basis, the number of inquiries for new load received recently, requests for interconnection studies and public announcements on proposed oil and gas developments, BC Hydro believes the Low Scenario to be the prudent minimum load growth profile on which to commit to provide incremental supply capacity and energy notwithstanding the lack of firm commitments for the potential new load.

The economic analysis does not include the impact of these possible new loads, but they are treated subjectively in the risk analysis section. Nor have the Scenarios been modified, rather BC Hydro is placing little weight on the 2007 Reference Forecast.
5.4 Load Forecast for the FN/RB region

Availability of electricity to BC Hydro from Alberta at any point in time will depend on the transmission capacity that is available from central Alberta to the FN/RB region and the combined load in that region.

5.4.1 Rainbow Lake Region (Alberta side of FN/RB region)

Figure 5-3 presents the forecast of the annual peak demand in the Rainbow Lake area.\(^\text{11}\)

5.4.2 Demand Side Management (DSM) in Fort Nelson region

BC Hydro has completed a localized forecast of the expected DSM savings that would be realized from the implementation of the DSM Option A that is being analyzed in the 2008 LTAP. Details of the DSM Plan are provided in the 2008 LTAP (Exhibit B-1). Expected electricity savings in the Fort Nelson region for the Reference Forecast by 2020 is 5.5 MW of

\(^{11}\) The forecast was received from the AESO on April 15, 2008. The load forecast is for the loads at the Alberta substations 747S, 748S, 779S, 791S, 795S, 797S, 828S, 850S, 786S, 832S, 890S.
demand and 37.9 GWh/year of energy. No specific cost has been calculated for the Fort Nelson region, but the overall DSM Option A portfolio of programs in the 2008 LTAP is shown to be one of the lowest cost options available to BC Hydro.

Given the DSM savings are significantly smaller than the load/resource gap to be filled and are available at a much lower cost than any of the supply options, BC Hydro has completed all of the portfolio analysis assuming the estimated DSM savings are acquired, as forecast.

Any specific requests with respect to this DSM are part of BC Hydro’s DSM Plan that is addressed in the 2008 LTAP.

It is assumed that any additional DSM that may be available if the projects underlying the new loads in the Low, Mid and High Scenarios do materialize will be incorporated in the design and implementation of those projects. This means that the load Scenarios are effectively net of DSM potential.

5.4.3 FN/RB Load Scenarios net of DSM

Figure 5-4 presents the forecast peak demand for the combined region. In this Figure, the BC Hydro load is net of the DSM associated with the BC Hydro Reference Forecast.
5.5 Existing and committed resources

5.5.1 B.C. generation

BC Hydro owns and operates FNG. It is a natural gas-fired facility located 16 km south of the town of Fort Nelson. The current power plant is configured as a simple cycle gas turbine (SCGT) with an Alstom generator directly coupled to a General Electric (GE) LM 6000 gas turbine. The gas turbine’s nominal rated capacity for normal operation is 47 MW in the winter and 40 MW in the summer.\(^\text{12}\)

With an average forced outage rate (FOR) of 1.39 per cent over the last six years, the plant has been very reliable and BC Hydro is not expecting any material change in its reliability.\(^\text{13}\)

The operating experience for each year is provided in Table 5-1.

\(^{12}\) Modelling of the FNG is 47.8 MW in the winter and 39.5 MW in the summer.

\(^{13}\) The FOR = Forced Outage Hours / (Annual Hours – Planned Outage Hours) = 114/( 8760 – 597 )
### Table 5-1  FNG Outage Experience

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned Outage</td>
<td>1365</td>
<td>960</td>
<td>382</td>
<td>238</td>
<td>312</td>
<td>326</td>
<td>597</td>
</tr>
<tr>
<td>Forced Outage</td>
<td>101</td>
<td>81</td>
<td>235</td>
<td>123</td>
<td>62</td>
<td>79</td>
<td>114</td>
</tr>
<tr>
<td>Total</td>
<td>1466</td>
<td>1042</td>
<td>617</td>
<td>361</td>
<td>374</td>
<td>405</td>
<td>711</td>
</tr>
</tbody>
</table>

### 5.5.2 Contract Sales

When FNG is running, any excess production to the needs in the local BC Hydro service area is exported to Alberta. This includes energy sales and sales of the reliability-based service TMR. Powerex is responsible for these market price-based sales arrangements.

### 5.5.3 Transmission from Rainbow Lake to Fort Nelson

There is a single circuit 144 kV transmission line (named 1L359 on the B.C. side of the border) connecting Fort Nelson to Rainbow Lake. Its reliability data for the ten-year period January 1997 to December 2006 is provided in Table 5-2. The physical transfer limit of the line from Rainbow Lake to Fort Nelson is assumed to be 117 MW.

### Table 5-2  Outage Experience of 1L359

<table>
<thead>
<tr>
<th>Circuit</th>
<th>Total Transient Forced Outages</th>
<th>Sustained outage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Transient Forced Outages Freq. Per year</td>
<td>Total Outages</td>
</tr>
<tr>
<td>1L359</td>
<td>1</td>
<td>0.10</td>
</tr>
</tbody>
</table>

### 5.5.4 Alberta Committed Transmission Capacity to the FN/RB Region

At present, the combined transmission capacity into the region is capable of meeting 130 MW of FN/RB area load. However, to sustain this level of transmission capacity, an equivalent amount of generation must be providing TMR in the region to meet the under
voltage security requirements.\[^{14}\] This results in effectively no net import to the FN/RB region under normal conditions, notwithstanding the identified transmission capacity.\[^{15}\]

Any load served above 130 MW is currently being served on a curtailable basis.

The AESO received approval from the AUC in August 2006 to upgrade transmission into the Alberta north-west (called Northwest Alberta Area Upgrade project), the region that feeds the FN/RB region. The approved upgrades will increase the overall capability to meet area load to 145 MW in 2011 without the need for any TMR operation. The base case for Alberta-based transmission in the 2008 FN RP/LTAP is the existing and committed transmission system is called AESO A0 and reflects the above-documented current and committed transmission capacity.

Given the forecast load growth on the Alberta side of the FN/RB region, the physical supply capability at the B.C./Alberta border to support Fort Nelson load supplied by BC Hydro is expected to be as shown in Table 5-3.

The TMR requirement to be provided by FNG and Rainbow Lake generation is expected to decline between now and 2011 as the approved and committed new reactive support is added to the Alberta system.

5.5.5 Contract purchases

The FDS is a unique rate provided to BC Hydro, but is based on the same principles as the AESO’s transmission capacity service (DTS) to customers interconnected to the high voltage network in Alberta.

The current FDS capability to 28.5 MW has a five-year termination notice and is assumed to be available to BC Hydro in the long term. The additional 10 MW curtailable capacity is also assumed to be available in the long term based on the same termination provisions, with the difference being that it is being supplied on an interim tariff.

\[^{14}\] Other generation in the FN/RB region includes five units in Rainbow Lake, however, only three units are operational.

\[^{15}\] The transmission capacity is, in effect, operational contingency reserve available for N-1 support.
Table 5-3  Transmission Capability available to BC Hydro

<table>
<thead>
<tr>
<th>Year</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011(^{16})</th>
<th>2011(^{17})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm (no TMR)</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>Gradually increasing to 28.5</td>
<td>39</td>
</tr>
<tr>
<td>Firm (with TMR)</td>
<td>28.5</td>
<td>28.5</td>
<td>28.5</td>
<td>74</td>
<td></td>
</tr>
<tr>
<td>Curtailable</td>
<td>10.0</td>
<td>10.0</td>
<td>10.0</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Total with Curtailable</td>
<td>38.5</td>
<td>38.5</td>
<td>38.5</td>
<td>74</td>
<td></td>
</tr>
</tbody>
</table>

5.6  The current and committed load/resource balance

The following planning load/resource balance analysis is based on peak demand only. As long as the peak demand is forecast to be reliably met, there is no expectation of an energy reliability shortfall.

Figure 5-5 presents the load/resource balance before considering reliability and the need for reserves in the region to meet the Partial N-1 reliability measure.

BC Hydro is assuming that the committed 38.5 MW (28.5 MW firm plus 10 MW curtailable) from Alberta will become firm by 2011 and will continue to be available to BC Hydro. The amount expected to be available is presented in Figure 5-5 and, as indicated, would require varying levels of TMR support through time as a result of load growth in the Rainbow lake region.

\(^{16}\) The current physical requirement for curtailable load should be alleviated by 2011.

\(^{17}\) As AESO A0 is implemented.
As described in section 3.1, there must be resources available that are sufficient to supply the customer demand even when the largest single resource is out of service (the largest single contingency; N-1 criteria). FNG is currently the largest single contingency in the FN region.

The N-1 Load/Resource Balances presented in the 2008 FN RP/LTAP (first shown in Figure 5-6) are based on the N-1 measure. In that respect, the load/resource balances compare (1) the full supply capability, putting all supply resources in the supply stack, against (2) the largest single local generating facility considered the contingency in any year being analyzed added to the annual peak demand for that year for the Reference Forecast and Scenarios.

In this representation, the capacity of FNG has been added to the Reference Forecast and Scenarios in all years to reflect the N-1 condition. The gap to the supply (also including the FNG) represents the shortfall in meeting the N-1 reliability measure.
As presented in Figure 5-6, there is insufficient capacity currently available to reliably meet the customer demand. The Load/Resource Balance for 2008 shows there is a shortfall in supply of approximately 5 to 10 MW even if none of the new load growth considered in the Scenarios becomes a reality.  

The Reference Forecast and the Scenarios do not assume any reduction in load in Fort Nelson resulting from the indefinite closure of the Canfor mills. Each mill has a requirement of approximately 6 to 8 MW.

Figure 5-6  Peak Load/Resource Balance including N-1 Reserve Requirements

5.7 Electricity Market Prices

The 2008 FN RP/LTAP uses BC Hydro’s Electricity Price Forecast as an input. This is the same electricity price forecast that is used in, and presented in Chapter 4, of the 2008

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18 The AESO’s current 10 MW curtailable load requirement described in section 2.2 is as a result of this N-1 reliability shortfall.

19 The load/resource balances including reserve requirements add the largest single contingency at any one time period to the load scenario. All supply sources are represented as being available. Any gap (load with N-1 being above the supply) represents a shortfall in ability to meet an N-1 reliability condition.
LTAP. As identified in Chapter 4 of the 2008 LTAP, the expected impact of GHG offset costs are reflected in the forecasts of electricity market prices based on the Linked Markets forecast of GHG offset costs.

5.7.1 B.C. Lower Mainland Price

Figure 5-7 presents BC Hydro’s Electricity Price Forecast in 2006 dollars for the BC Hydro Lower Mainland (B.C. Border) price. This is the electricity market price that would apply in the portfolios where a BCTC transmission line is assumed to connect Fort Nelson to the Peace River region.

5.7.2 Alberta AESO Market Price

Figure 5-8 presents BC Hydro’s January 2008 Electricity Price Forecast in 2006 dollars for the Alberta electricity market (AESO market price). It is the price forecast used to calculate energy purchase costs for energy purchased from Alberta.

As identified in section 4.4.2 of the 2008 LTAP, the electricity market prices include some allowance for the expectation of GHG offset requirements in the Western Electric APPENDIX N1 to BC Hydro’s 2008 LTAP

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Coordinating Council (WECC). The forecast market prices for Alberta are based on the simulations of the WECC, as measured at the Alberta AESO node.

With respect to Alberta, the assumption was that offsets would be required for GHG emissions above 600 tonnes of CO₂e/GWh. Therefore, the costs for GHG offsets above the 600 tonnes of CO₂e/GWh level are assumed to be priced into AESO electricity market price in the analysis in the FN RP/LTAP. Risk analysis regarding the possible requirement to offset GHG associated with imports is set out in section 7.5.2.4.2.

**Figure 5-8** BC Hydro 2008 Forecast of Electricity Prices in the AESO Market

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5.8 **Natural Gas Prices**

Figure 5-9 presents the BC Hydro forecast natural gas prices underlying the BC Hydro 2008 Electricity Price Forecast. This gas price forecast is the same forecast as used in Chapter 4 of the 2008 LTAP.

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20 Exhibit B-1, page 4-20, lines 14-21.
Gas transportation from the Station 2 hub is estimated to be a credit (negative cost) of $0.10/GJ on capacity and 0.75 per cent fuel (energy).

As described in Chapter 4 of the 2008 LTAP, the B.C. Government’s February 2008 Budget declared that there would be a carbon tax added to natural gas starting in July 2008 at $0.50/GJ and increasing annually to $1.50/GJ in 2012. This additional cost is included in the analysis as a separate operating cost and not included in the commodity cost forecast presented in Figure 5-9. Subsequent to the original filing of the 2008 LTAP, the B.C. Government introduced and passed the Climate Tax Act and released the Climate Change Action Plan. The Climate Action Plan in particular makes it more certain that either the carbon tax or the GHG offset costs, but not both at one time, would apply to a generating facility.

As a result, BC Hydro updated its original assumption regarding the application of the B.C. carbon tax by removing the carbon tax in situations where the GHG offset requirement would apply. This is further described in the response to BCUC IR 1.94.1 (Exhibit B-3).
5.9 Greenhouse Gas Cost Forecasts

The GHG cost forecast is the forecast developed by Natsource and presented in Chapter 4 of the 2008 LTAP.

Figure 5-10 Forecast of GHG Offset Costs

6 Planning Horizon Resource Options

6.1 Upgrade existing SCGT (FNU2 or FNU3)

BC Hydro identified two alternative Resource Smart projects to upgrade the existing FNG SCGT to be a CCGT. Both alternatives involve upgrading the existing gas turbine, upgrading or replacing the current heat recovery boiler to a once through steam generator (OTSG) and installing a new steam-driven turbine-generator set. The primary distinction between the two alternatives is that FNGU Case 2 (FNU2) does not include duct firing while FNGU Case 3.2 (FNU3) does. FNU2 would provide approximately 10 MW of capacity from substantially the same amount of natural gas as is currently used at FNG. FNU3

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21 Duct firing is described at Exhibit B-1-7, page 3, footnote 3.
provides approximately 26 MW of capacity, and would require additional natural gas for the capacity increment above FNU2.

Assumptions with respect to FNU2 and FNU3 for the analysis are provided in Table 6-1. The capital cost used in the economic analysis is presented in 2012 dollars and includes project reserve and interest during construction (IDC). Consistent with past practice and BCUC determinations, the economic analysis of FNU2 and FNU3 is based on incremental costs excluding corporate overhead.

<table>
<thead>
<tr>
<th>Plant Factors</th>
<th>FNU2</th>
<th>FNU3</th>
<th>Winter Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental Capacity</td>
<td>MW</td>
<td>10</td>
<td>26</td>
</tr>
<tr>
<td>Capital Costs</td>
<td>$M</td>
<td>86.3</td>
<td>129.1</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$/MW-Mo</td>
<td>6,100</td>
<td>6,100</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$K/Mo</td>
<td>336</td>
<td>336</td>
</tr>
<tr>
<td>Power Variable O&amp;M</td>
<td>$/MWh</td>
<td>1.10</td>
<td>1.10</td>
</tr>
<tr>
<td>Operations Variable O&amp;M</td>
<td>$/Fired Hour</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>Earliest Availability</td>
<td>Dec 2011 (for 2012)</td>
<td>Dec 2011 (for 2012)</td>
<td>Subject to planning, regulatory, financing and development risks</td>
</tr>
</tbody>
</table>

6.2 New 56 MW CCGT in Fort Nelson

Two alternatives that would exist for a new CCGT in Fort Nelson would be to upgrade FNG with a second CCGT of similar characteristics as the FNU2 or the FNU3 projects on the same site, or to develop a new greenfield CCGT project of similar size. The characteristics

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22 BCUC Decision Order C-8-07 (Revelstoke Unit 5 CPCN), page 59.
23 Costs are in 2008 dollars except as noted.
24 Long Term Service Agreement (LTSA)
for either alternative are assumed to be the same for the analysis in the 2008 FN RP and are presented in Table 6-2.

A second CCGT could add approximately 55 to 75 MW of capacity. However, a new CCGT is not an alternative to FNGU because a new CCGT would not be able to meet an ISD of 2012. The earliest ISD for installing a second CCGT in the Fort Nelson area depends on whether:

• the second CCGT is a Resource Smart project sited at BC Hydro’s FNG site (named the Fort Nelson Expansion Project); or

• the second CCGT is a new, greenfield development.

BC Hydro has, for purposes of estimating the ISD for the two CCGT scenarios, assumed a two to three-year period for the engineering, procurement and construction.

In the analysis, the new CCGT, called C57, is set to be the same size and performance characteristics as the FNU2.

The assumed C57 costs are summarized in Table 6-2 and are based on data from the recently completed Resource Options Update that forms part of BC Hydro’s 2008 LTAP filing. The cost may not reflect current market or local conditions, and is more uncertain than the cost estimates for FNU2 or FNU3.

25 The Resource Options Update is contained in Appendix F1 of the 2008 LTAP.
Table 6-2 New CCGT (C57) in Fort Nelson or at FNG

<table>
<thead>
<tr>
<th>Plant Factors</th>
<th>Units</th>
<th>C57</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental Capacity</td>
<td>MW</td>
<td>56</td>
<td>Winter Rating</td>
</tr>
<tr>
<td>Capital Costs</td>
<td>$M</td>
<td>174.2</td>
<td>Fixed Direct cost in 2012 dollars, excluding allocated corporate overhead</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$/MW-Mo</td>
<td>5,333</td>
<td>Infl Adj Staff, Fixed Maintenance, LTSA, Grants in lieu, etc</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$K/Mo</td>
<td>293</td>
<td>Infl Adj Dollar Cost of Fixed O&amp;M</td>
</tr>
<tr>
<td>Power Variable O&amp;M</td>
<td>$/MWh</td>
<td>3.40</td>
<td>Infl Adj Covers water treatment and other variable maintenance</td>
</tr>
<tr>
<td>Operations Variable O&amp;M</td>
<td>$/Fired Hour</td>
<td>150</td>
<td>Infl Adj Covers LTSA charges and own-forces O&amp;M</td>
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<tr>
<td>Earliest availability</td>
<td>for 2014</td>
<td></td>
<td>subject to planning, regulatory, financing and development risks</td>
</tr>
</tbody>
</table>

6.2.1 Fort Nelson Expansion Project

FNG has property available, and was originally designed, to be increased in size. Most of the infrastructure exists to double the size of the project, or possibly more.

BC Hydro has initiated an Identification phase study for the Fort Nelson Expansion Project. The study is to develop a plant design and cost estimate to an accuracy range of +65/-35%. The study will look at several new generating size options, including duplicating the FNGU, whether as FNU2 or FNU3. The study is expected to be completed in the first quarter of 2009.

If a second CCGT, duplicating the FNU2, were installed at that site, it would provide approximately an additional 56 MW of winter capability. Some of the existing infrastructure has been sized for this second CCGT which would provide some economies of scale relative to a similar new, greenfield CCGT as described in the following section. However, in this analysis the cost of expanding FNG with a second CCGT was assumed to be the same as the cost of a generic new, greenfield CCGT, which is summarized in Table 6-2.

26 Costs are in 2008 dollars except as noted.
The earliest ISD for the Fort Nelson Expansion Project is likely late 2013, for the following reasons:

- Unlike FNGU, the Fort Nelson Expansion Project would trigger the *B.C. Environmental Assessment Act (BCEAA)* because pursuant to the Reviewable Projects Regulation it would be a modification to an existing facility resulting in FNG having a rated nameplate capacity that has increased by 50 MW or greater. Pursuant to section 8 of *BCEAA*, no construction could begin on the Fort Nelson Expansion Project until an Environmental Assessment Certificate (*EAC*) had been obtained. BC Hydro estimates that the *BCEAA* process would take approximately 14 months from submission of the project description to the B.C. Environmental Assessment Office to issuance of the EAC. In estimating the length of time of the *BCEAA* process, BC Hydro has taken into account the fact that some of the existing infrastructure could be used; BC Hydro estimates a longer *BCEAA* process for a greenfield CCGT (see below). BC Hydro has also concluded that *Canadian Environmental Assessment Act (CEAA)* is likely not triggered for the Fort Nelson Expansion Project; this assumption may not hold for a greenfield CCGT. See below.

- Similar to FNGU, a determination for Fort Nelson Expansion Project expenditures would be sought from the BCUC pursuant to section 44.2 of the *UCA*. This process could result in a hearing lasting approximately seven months. This process could occur while the *BCEAA* process is occurring as long as BC Hydro had a good estimate of the likely environmental mitigation costs. BC Hydro assumed this to be the case with respect to the Fort Nelson Expansion Project.

### 6.2.2 New Greenfield CCGT in Fort Nelson

One available option with the necessary capacity reliability is a new greenfield CCGT in the Fort Nelson area. This analysis assumes a nominally rated 50 MW, one on one configuration based on a GE LM 6000 machine, which is a similar CCGT configuration to what the FNG project will be once upgraded. Given local conditions and the similarity to FNG, it is also assumed to be capable of providing 56 MW (winter peak conditions).

The earliest ISD for a new greenfield CCGT is likely to be mid to late 2014, for the following reasons:
• Pursuant to Policy Action No. 13 of the 2002 Energy Plan, this project would not be a Resource Smart project and therefore must be an independent power producer (IPP) project. A copy of Policy Action No. 13 is attached as Attachment 2. Accordingly, a power acquisition process – whether a Call for Tenders or a Request for Proposals – would be required. The power acquisition process would likely take approximately 18 months from development through to filing any Electricity Purchase Agreement (EPA) awarded to an IPP with the BCUC pursuant to section 71 of the UCA. Difficult issues of dispatchability and which party – the IPP or BC Hydro - should bear the natural gas price and GHG risks would need to addressed both in the EPA and in the section 71 filing.

• The ISD assumes that BC Hydro would not seek a determination pursuant to section 44.2 of the UCA for expenditures related to the new greenfield CCGT, prior to the power acquisition process and the section 71 filing. Ministerial Order M202 exempts IPPs selling electricity to BC Hydro from the requirement to obtain a Certificate of Public Convenience and Necessity. However, BC Hydro may wish to reduce regulatory risk and seek a BCUC determination.

• Again, unlike the FNGU, a new greenfield CCGT would trigger BCEAA because, under the Reviewable Projects Regulation, it would be a new facility with a rated nameplate capacity of equal to or greater than 50 MW. In BC Hydro’s view, the environmental assessment process for a new greenfield CCGT would be approximately 18 months, longer than for the second CCGT at the FNG site because: (1) there may be location impact issues; and (2) CEAA may be triggered. Generally speaking, BC Hydro’s experience has been that IPPs are reluctant to advance too far into the BCEAA process without an EPA, and that accordingly the BCEAA process would likely occur after the section 71 process.

6.3 New 31 MW CCGT in Fort Nelson

In the second round of Information Requests (IR) the BCUC requested that BC Hydro include a CCGT of approximately 27.7 MW in its analysis. BC Hydro developed an early investigative cost estimate for a 31 MW CCGT (at the FNG site or greenfield site), called C31 in the analysis.

27 BCUC Information Requests 2.222.2 and 2.222.3 (Exhibit A-5).
To respond to the above mentioned IRs, the portfolios that include this C31 do not include either FNU2 or FNU3. Such portfolios would be mutually exclusive to building a second CCGT on the existing site and may create some conflicts with FNU3.

BC Hydro estimated the cost for this hypothetical 31 MW CCGT from the estimates included in the Resource Options Update for the generic 50 MW CCGT and adjusted for project size based on industry market literature. As such, the cost estimate may not reflect current market or local conditions, and is more uncertain than the cost estimates for FNU2 or FNU3.

Development issues and risks would generally be the same as those identified with respect to the 56 MW CCGT (greenfield or FNG site) with the following exceptions:

- The C31 project would not trigger BCEAA, but may trigger CEAA if it is a greenfield site;
- The cost to arrange water and effluent discharge would need to be added to the project cost; and
- If such a project were to be sited at FNG as an alternative project to the Fort Nelson Expansion Project, there would be additional time required (later ISD) for development and design; or
- If the project is developed at a site other than FNG a new site and transmission interconnection infrastructure would be required.

The assumed cost for C31 used in the analysis is summarized in Table 6-3.
Table 6-3 New 31 MW CCGT (C31) in Fort Nelson or at FNG28

<table>
<thead>
<tr>
<th>Plant Factors</th>
<th>C31</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental Capacity</td>
<td>MW</td>
<td>31</td>
</tr>
<tr>
<td>Capital Costs</td>
<td>$M</td>
<td>143.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$/MW-Mo</td>
<td>5,333</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$K/Mo</td>
<td>165</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power Variable O&amp;M</td>
<td>$/MWh</td>
<td>3.40</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operations Variable O&amp;M</td>
<td>$/Fired Hour</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Earliest availability</td>
<td></td>
<td>for 2014</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

6.4 Results of Request For Expressions Of Interest (RFEOI) for Clean Resources

BC Hydro issued a RFEOI for the provision of clean or green electricity from IPPs in the Fort Nelson area. The request was issued in July 2007, with a deadline for responding of September 30, 2007.29 BC Hydro’s 2007 RFEOI received a total of sixteen responses (one response was disregarded as ineligible because it was not clean or green). The submissions, broken down by project type, were: six bioenergy, two small hydro, six wind, one geothermal and one pumped storage.

Since this was an RFEOI, the submissions did not provide a commitment from the proponents. As a result, these potential projects can only provide BC Hydro with an indication of whether it is possible to conduct a successful clean or green electricity call in the Fort Nelson region.

In the Fort Nelson region, BC Hydro requires a reliable source of dependable capacity that is dispatchable and economically capable to produce energy at relatively high capacity.

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28 Costs are in 2008 dollars except as noted.
29 The notice of the RFEOI, along with a summary of the responses, is provided in Appendix Q to the 2008 LTAP (Exhibit B-1-1).
factor. This reliability is critical at all times, including during LLHs when the region’s gas-
turbine generators may be dispatched down to minimum MW levels, or even dispatched off.

Of the sixteen responses, only the bioenergy projects could potentially provide this level of
reliability in supply. The RFEOI results provide some indication that there is a possibility of
locating a wood waste biomass generating station in the area, but that it may not be
dispensable, and would be small, have relatively large fuel supply risk particularly with the
uncertainty at Canfor, and relatively expensive (between 150 $/MWh and 175 $/MWh).

It is unlikely that BC Hydro’s supply need could be met by clean or renewable resources
alone, given the timing and the amount of the potential load growth in the area.

In the analysis, a generic 10 MW biomass purchase contract priced at 160 $/MWh in 2012
escalating at 50 per cent of the Consumer Price Index, reflecting approximately 150 $/MWh
levelized cost over the term of the analysis. It is assumed the plant would be available from
2012 through to the end of the study period, 2027; and that the plant would not be
dispensable.

Other than the above, BC Hydro did not obtain any information of any realistic potential for
other clean or renewable supply options available in the Fort Nelson area that would meet
BC Hydro’s upcoming supply requirements.

6.5 Supply from Alberta

A base assumption in BC Hydro’s FN RP/LTAP analysis is that BC Hydro would be able to
contract for the purchase of any physical supply that is available from the AESO at the
B.C./Alberta border.

6.5.1 Transmission Upgrade Options

The current transmission capacity to the FN/RB region is sufficient to provide BC Hydro with
38.5 MW of capacity. At this capacity, TMR is required and firm load may have to be
curtailed.
As described in section 5.5.4, committed transmission upgrades in Alberta are expected to increase the possible capacity into the FN/RB region to 145 MW by 2011 absent any need for TMR or curtailable loads. Additional transmission expansion in the Alberta northwest will be required if the AESO is to provide additional service to BC Hydro.

The AESO has provided BC Hydro with early Investigation phase estimates of costs to increase the transmission capacity to Rainbow Lake. A fourth alternative considered by the AESO was rejected and not offered because it was uneconomic relative to the other AESO alternatives. The three alternatives and transmission capacity levels are as shown in Table 6-4. The AESO’s base plan is to have sufficient transmission capacity to meet a region’s requirements without requiring TMR operation. However, BC Hydro understands that there would be some additional capacity that would be available with TMR operation, assumed to be 35 MW in each case.

Table 6-4

<table>
<thead>
<tr>
<th>Description</th>
<th>In-service Date</th>
<th>Capacity w/o TMR (MW)</th>
<th>Marginal Losses (%)</th>
<th>Capital Cost(^{30}) ($M)</th>
<th>Levelized Cost(^{31}) ($M/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AESO A1. Convert the new Wesley Creek to Hotchkiss double circuit line to 240 kV operation</td>
<td>2011</td>
<td>170</td>
<td>36%</td>
<td>35</td>
<td>2.9</td>
</tr>
</tbody>
</table>

\(^{30}\) Costs were reported to be in 2008 dollars with a +/- 50 per cent capital cost band of uncertainty.

\(^{31}\) Nominal dollars.
BC Hydro expects that AESO A1 will be developed either by the AESO based in internal requirements or as a result of BC Hydro’s request for additional capacity that has been initiated by the Preliminary Assessment Application described in section 7.3. If the AESO proceeds with this project, the increase in capacity could be available for 2011.

This transmission expansion project is required if the AESO is to provide additional service to BC Hydro. Once upgraded, BC Hydro expects there to be approximately 64 MW in 2011 and 62 MW in 2012 available at the interconnection without requiring TMR. This capacity level declines as load grows in the Rainbow Lake region of Alberta.

BC Hydro considers AESO A2 will have increased development risk relative to AESO A1 because it includes the construction of a new 230 km 144 kV transmission line. The AESO A2 would face more public and regulatory scrutiny relative to AESO A1 as the latter requires very little new infrastructure, no new transmission towers or line and a much lower cost.

Transmission capacity assumed to be available to BC Hydro at the B.C./Alberta border is as shown in Figure 6-1 for AESO A0, A1 and A2. As stated in section 5.5.3, the maximum transfer of the line from Rainbow Lake to Fort Nelson is assumed to be 117 MW.
The above transmission upgrade options may include some additional reactive support in the FN/RB region, some of which may be best located in Fort Nelson.

As shown in Figure 6-1, AESO A2 with TMR would be sufficient to utilize all capacity on the existing circuit from Rainbow Lake to Fort Nelson, at least to a Partial N-1 reliability measure. AESO A4 would add 150 MW of capacity relative to AESO A2 at an added cost of $175 million. Such an increment to capacity would require a second circuit from Rainbow to Fort Nelson if the capacity were to be relied on to meet the load in Fort Nelson. No additional analysis is included with respect to option AESO A4.

Additional transmission and area supply studies will have to be undertaken by the AESO to obtain project estimates for the various transmission solutions that would be sufficient for confirming additional service to BC Hydro.

6.5.2 AESO transmission losses

Marginal losses for sending electricity to the FN/RB region (sending end loss percentages) are very high. An approximation of the losses is as shown in Figure 6-2.
Transmission losses in the AESO are included in the transmission system costs as a Loss Factor for each location on the transmission system. The Loss Factor is based on a computation of the impact of incremental loads on average losses at each location for each year. The calculation is done annually and the Loss Factor is capped at +/- 12 per cent (sending end MW).\textsuperscript{32}

Estimates of Loss Factors for the base and two transmission options are presented in Figure 6-3.

\textsuperscript{32} Alberta Transmission Regulation, A.R. 86/2007
The analysis in the 2008 FN RP includes both marginal loss analysis and analysis based on the annual AESO Loss Factor. The analysis assumes no generation in the Rainbow Lake region under normal conditions. For a combined load of 150 MW (forecast FN/RB region load in 2012 based on the Reference Forecast), the AESO Loss Factor would be 12 per cent for the committed transmission and AESO A1 if there was no assumed generation in Fort Nelson.

In the case of Fort Nelson, the interconnection point to the AESO is measured at the border. This is the point that the AESO sets its Loss Factor with respect to Fort Nelson. BC Hydro assumed the losses from the border to Fort Nelson are four per cent for deliveries in either direction.

The average of the total losses from each scenario tested is reported in the economic analysis. Any dispatchable generation in Fort Nelson is assumed to be dispatched against the BC Hydro Electricity Price Forecast for the AESO adjusted for losses and GHG costs.
6.5.3 Firming credit for SD 10

Starting in 2016, a capacity firming charge/credit is calculated to reflect the relative impact any supply portfolio may have on BC Hydro’s requirement to be self-sufficient by 2016. The firming premium is the difference between the cost of firm supply for the integrated BC Hydro system net of the relevant BC Lower Mainland electricity market price. The cost of firm supply is calculated based on the annual capacity surplus or shortfall in the Fort Nelson region (installed MW as compared to the annual peak demand) priced at BC Hydro’s Reference Price of $88/MWh (Lower Mainland price in 2006 dollars) assuming a 65 per cent load factor.

6.5.4 GHG obligations on imports

Energy purchased from the AESO is priced at the relevant electricity price scenario. As described in section 2.3.3, the GHG Cap and Trade Act contemplates such a requirement and leaves its implementation to regulation. Since such regulations have not been issued, no adjustments have been made in the base analysis.

BC Hydro’s current assessment is that any imports from Alberta would be from sources that average in excess of 600 tonnes of CO₂e/GWh. Given that the BC Hydro Electricity Price Forecast incorporates an assumption of offset requirements to 600 tonnes of CO₂e/GWh in the case of Alberta, any GHG emission level above that level is already priced into the market price forecast, and therefore into the base economic analysis provided in the 2008 FN RP/LTAP.

Given the increased likelihood of some offset requirement, BC Hydro has added a section in its risk analysis that addresses the impact of such a requirement being in place by 2012.

6.6 New Transmission interconnecting Fort Nelson to BCTC integrated system

6.6.1 Transmission Upgrade Option

Interconnecting the Fort Nelson region to the BCTC interconnected system would require a high voltage line, likely 230 kV, to be constructed from the Peace River region to Fort Nelson. This line, called BCTC B1 in the analysis, would be approximately 300 km in length.
This transmission distance to a major generating station is much shorter than the comparable interconnection to the Alberta system.

The early investigation phase estimate of the line cost is $403 million and the expected earliest ISD being by 2015. The loss factor to send electricity to Fort Nelson relative to the BC Hydro Lower Mainland is expected to be -10.3 per cent (sending end loss calculation). This is an incremental loss of 7 per cent from the Peace River region to Fort Nelson and a loss credit of 16.1 per cent from the Lower Mainland to the Peace River region).

BC Hydro has requested that BCTC complete a planning level assessment with respect to a new transmission connection between the Peace region and Fort Nelson. The study will (1) focus on the physical interconnection options for a wide range in future regional load; (2) recognize the current and planned generation and transmission facilities; (3) provide transmission capability, schedule and cost estimates for identified options, and (4) consider the issue of the ongoing interconnection with Alberta.

Construction of an interconnection to the main BCTC system may require the line from Fort Nelson to Rainbow Lake to be operated in a normally open (disconnected) state. If this option is selected, detailed system analysis would be required as part of further study to identify operating constraints. The reliability of the new transmission line should be similar to that of the line from Rainbow Lake to Fort Nelson. System reliability at the source end in the Peace River region is much stronger than that at the Rainbow Lake substation.

6.6.2 Capacity and Energy Supply associated with BCTC B1

If a new transmission line to the BCTC interconnected system were to be the selected solution, the incremental load to be served in the Fort Nelson area would need to be added to the BC Hydro interconnected system load which would increase the capacity and firm energy requirements of the interconnected system.

For supply planning, it is assumed that any capacity surplus or deficit in the Fort Nelson region would require or allow an offsetting amount of firm supply on the BC Hydro integrated system. The cost of the firm supply is calculated based on the annual capacity surplus or
shortfall priced at BC Hydro's Reference Price of $88/MWh (Lower Mainland price in 2006 dollars) assuming a 65 per cent load factor.

For the portfolios based on the BCTC interconnection, any dispatchable generation in Fort Nelson is assumed to be dispatched against the B.C. Lower Mainland Electricity Price Forecast adjusted for losses unless required as must run generation.

7 Option/portfolio analysis

7.1 Analytical approach and Portfolio Construction

Each of the long-term solutions involves the acquisition of new capacity and energy from one or a combination of the resource options identified in section 6. These resource options generally would not be available until 2012. Therefore, there are two relatively distinct time periods:

- the short-term where the plans are based on making the most of the assets that currently exist; and

- the planning horizon where any of the resource options could be available to meet any gap (shortfall) in BC Hydro’s load/resource balance in the region.

With respect to the former, there is a probability that there will be insufficient supply resources to reliably meet all requested load additions. The approach taken is to identify the options available to BC Hydro to manage the load growth and acquire any incremental transmission capacity as it becomes available from the AESO until new resources can be made available. No trade-off analysis is provided for the period prior to 2011 as there is no realistic alternative.

With respect to the latter, portfolios of resource additions are tested against the future load scenarios. The analysis includes scenarios of future natural gas and spot market electricity price forecasts.

The transmission cost is based on the Northwest Transmission Line. That cost estimate is in 2013 dollars and includes costs for construction at 287 kV and the substation upgrades.
May 31, 2009

Export and Import Rates XTS and ITS Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Export and Import Rates XTS and ITS Working Group

The first meeting of the Export and Import Rates XTS and ITS Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 11:00 AM to 1:00 PM
- **Date:** Tuesday, June 2, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Light working lunch and beverages

This working group includes the following members:

- ATCO Power: Kim Johnston
- IPCAA: Vittoria Bellissimo
- MATL: Bob Williams or Paul Kos
- NaturEner: Juliane Kniebel-Huebner
- Powerex: Lisa Cherkas
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma, and Gordon Nadeau

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. Powerex has already advised that they will participate in this first meeting by conference call.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   
2. **Review agenda**
   
3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
— 2 —

- Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
- A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 **Background for Export and Import Rates XTS and ITS** 11:20 AM

- Please review the enclosed information before the meeting, if possible:
  (a) Compilation of legislation and policy relating to exports and imports, including excerpts from the Electric Utilities Act, Transmission Regulation, Transmission Development Policy, and Electricity Policy Framework
  (b) Discussion of export and import rates in section 7 (pages 76-91) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (c) Discussion of export and import rates in section 5.8 (pages 33-37), and of merchant rates in section 7.4 (pages 78-80), of Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
- Is there other background that participants consider particularly relevant?

5 **Scope for Export and Import Rates XTS and ITS Working Group** 11:30 AM

- Definition of “firmness” for export and import transmission service
- Tariff implications of priority distinctions for export and import services
- Rate design principles for higher priority export and import services
- Similarities and differences between domestic and intertie transmission service and rates
- Allocation of transmission costs to export and import rates
- Working group will not review or discuss the following items which are being addressed through the Market Advisory Committee (MAC) Interties Subcommittee:
  - restoration of intertie capacity and construction of new interties;
  - ATC (Available Transfer Capability) levels;
  - business practices for interties, including curtailment, scheduling, allocation of ATC among interties, and other procedures; and
  - market and pool price interaction and impacts of exports and imports.

6 **Firmness and priority distinctions for export and import rates** 11:45 AM

- AESO’s current tariff includes two opportunity export rates (one of which will not be available until an OASIS is implemented) and a single opportunity import rate
- What would firm rates imply, and do conditions exist such that firm rates can be offered?
- What do different priorities of opportunity rates imply?

7 **Rate design principles for higher priority export and import services** 12:15 PM

- Government policy suggests firm export service should be priced at the same level as firm domestic load service, and firm import service at the same level as firm domestic generation service
Government policy also suggests opportunity services should be priced at a discount from firm services.

All AESO rates, including those charged for export and import services, must be just and reasonable.

What does this mean for export and import services?

8 Follow-up required for next meeting 12:45 PM
- Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s) 12:55 PM

10 Adjourn 1:00 PM

This agenda and all other printed information related to the Export and Import Rates XTS and ITS Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
   - Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a "without prejudice" basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
Part 2 Independent System Operator and Transmission
Division 2 Independent System Operator Duties and Authority

Duties of Independent System Operator

17 The Independent System Operator has the following duties:

(a) to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy;

(b) to facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so;

(c) to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta....


Part 2 Transmission System Planning

Long term planning - 20-year plan

9 As part of its duties under section 17 of the Act, the ISO must

(a) prepare and maintain a long term transmission system outlook document that projects, for at least the next 20 years,

(i) the forecast load on the interconnected electric system, including exports of electric energy,

(ii) the anticipated generation capacity, including appropriate reserves and imports of electric energy required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports and exports of electric energy and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,
(v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate,

Long term planning - 10-year plan

10(1) As part of its duties under section 17 of the Act, the ISO must

(a) prepare and maintain a transmission system plan in greater detail than the long term transmission system outlook document, that projects, for at least the next 10 years,

(i) the forecast load on the interconnected electric system, including exports of electric energy,

(ii) the anticipated generation capacity, including appropriate reserves and imports of electric energy required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports and exports of electric energy and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,

(v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate,

(b) update the transmission system plan periodically as required, but at least every 2 years, including updating the plan to restore the interties referred to in section 16, and

(c) make the transmission system plan, including the assumptions and supporting data on which the plan is based, and the updates made to the plan, available to the public, and file copies of them with the Board for information.

Part 3 Transmission System Criteria and Reliability Standards

Matters taken into account

15(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must...

(g) make rules respecting the preparation of needs identification documents for, and the planning and processing of, enhancements or upgrades to transmission facilities that existed on August 12, 2004 for the purpose of providing transmission capacity to import or export electric energy to or from Alberta in
excess of the path ratings that existed on August 12, 2004 for those transmission facilities.

**Restoring interties existing on August 12, 2004 to their path rating**

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.

**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.

(2) When the ISO prepares a needs identification document under section 34(1) of the Act for an intertie described in subsection (1), the needs identification document must

(a) contain the information required by section 11(3), unless the ISO determines that any of those matters are not required,

(b) describe the extent to which the ISO will make use of the proposed intertie to provide system access service,

(c) contain proposed agreements, arrangements, rates and terms and conditions for the ISO’s use of the intertie, and

(d) contain any other information that the ISO considers necessary in view of the nature of the proposed intertie.

(3) A person proposing an intertie to which this section applies must assist the ISO in preparing the needs identification document.

(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

(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.

Part 6 Transmission System Losses, Charges and Credits

Transmission system loss factors

31(1) The ISO must make rules to

(a) reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors

(i) for each generating unit,

(ii) for each export path or group of export paths, as those terms are defined in the ISO rules respecting line losses,

(iii) for each import path or group of import paths, as those terms are defined in the ISO rules respecting line losses, and

(iv) for any other opportunity service customer in respect of whom the ISO determines a loss factor is to apply, based on their respective locations and their respective contributions, if at all, to transmission line losses...

(e) subject to section 33, provide a means through the application of a single calibration factor to adjust the amounts paid by the application of the loss factor described in clause (c) so that

(i) owners of generating units,

(ii) importers and the exporters of electric energy, and

(iii) any other opportunity service customers referred to in clause (a)(iv),
are charged or receive a credit so that they pay the actual cost of transmission line losses.

**Determination of transmission loss factors on and after January 1, 2009**

36 On and after January 1, 2009, the loss factors under this Part must be determined so that

(a) the owner of a generating unit must pay location-based loss charges or receive credits,

(b) importers of electric energy must pay location-based loss charges or receive credits

(i) determined in the same manner as for generating units, and

(ii) determined at the point where the import path, referred to in section 31(1)(a)(iii), connects to the remainder of the interconnected electric system,

(c) importers and exporters of electric energy must pay transmission line loss charges representing the average level of losses incurred in transporting electric energy on an import path or export path referred to in section 31(1)(a)(ii) and (iii), and

(d) a person that receives opportunity service where the ISO determines that a line loss factor applies under section 31(1)(a)(iv) must pay losses or receive credits that are determined in a similar manner as the losses and credits determined for owners of a generating unit.

**Part 7 Board Responsibilities**

**ISO tariff - transmission system considerations**

47 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 DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and

(ii) the amount payable by a DFO is recoverable in the DFO’s tariff,

(b) ensure owners of generating units are charged local interconnection costs to connect their generating units to the transmission system, and are charged a financial contribution toward transmission system upgrades and for location-based cost of losses, and
Transmission Development Policy (December 22, 2003)

2. **Background** (page 2)

Transmission development must also recognize that Alberta is part of, and connected to the rest of the North American electric grid. Inter-ties are an essential part of a competitive market both as a means to import power when needed, to export surplus energy, and to ensure that the competitive wholesale market functions effectively.

3. **Principles**

3.1. **Transmission – Foundation Principles** (page 3)

Adequate transmission is required to ensure that the electric system is reliable and efficient and to ensure that the competitive wholesale market functions effectively. Transmission development must recognize that Alberta is connected to a North American system. Inter-ties are an essential part of a competitive market both as a means to import power when needed and to export surplus energy.

The following principles summarize and further articulate the fundamental goal stated above.

6. Inter-ties are essential to a well-functioning market structure. Alberta is integrated with the electric systems of our neighbours. Transmission policy and the regulatory environment must facilitate open access to larger markets, while ensuring that Alberta’s needs are met.

7. The policy should support appropriate consideration of export projects including the benefits to Alberta consumers.

4. **Conclusions** (pages 9-10)

8. Transmission internal to Alberta should be reinforced so that under normal conditions, the existing inter-ties can import and export power on a continuous basis, in accordance with their design capability.

The design capability is defined as the maximum level at which the inter-ties can be operated, respecting NERC and WECC reliability criteria and without the use of must run generation.

Under normal conditions, the Alberta transmission system should be reinforced so that the BC Inter-tie is capable of transferring about 1,000 MW for exports subject to availability of generation RAS schemes and about 800 MW for imports subject to suitable load RAS schemes. Imports in excess of 800 MW on the BC Inter-tie require more careful consideration since they may place the Alberta system at considerable risk. The Saskatchewan Inter-tie should be capable of transferring 150 MW for import and export.
Inter-ties are an essential part of a competitive market both as a means to import power when needed, and to export surplus energy and to support effective functioning of the wholesale market. Without such capabilities, market signals and wholesale prices are distorted and unreflective of true market conditions. Since the ability of inter-ties to exchange electricity in both directions (i.e. import and exports) is essential to a robust wholesale market and a reliable electric system, the cost for internal reinforcements and RAS arrangements to allow the inter-ties to function as designed will be allocated to load.

It is recognized that a combination of market design and exercise of market power have constrained the use of inter-ties through BC. Alberta will continue with its efforts to ensure compatibility with its neighbouring jurisdictions and to address access issues with BC Hydro transmission and the Pacific Northwest. Alberta Energy will also continue to participate in RTO and related discussions to ensure Alberta’s interests are represented appropriately. However, due to the length of time needed for transmission upgrades, required upgrades to the internal transmission network must not be held in abeyance awaiting resolution of access issues with BC/US markets.

**Inter-tie Pricing**

The current practice of charging exporters who use non-firm transmission service (i.e. opportunity service) is appropriate. The opportunity export tariff will continue to recover a portion of the embedded costs of transmission wires, losses and ancillary services, while respecting the established practices for inter-regional electricity trade. Such non-firm transmission service should be priced at a discount from the firm transmission service rate. Firm export service may also be developed, with the expectation that this service will be priced at the same level as firm service in Alberta.

Alberta Energy also confirms that import variable charges will be removed coincident with discontinuation of the STS variable energy charge for generators. Loss charges will continue to apply to exporters and importers.

9. Projects primarily intended for export should be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries (i.e. the exporters). Where residual benefits to the internal grid are demonstrated, consumers may fund system upgrades, in a manner consistent with the benefits.

The ISO will be responsible for bringing forward such applications to the EUB in conjunction with project proponents. For dedicated export projects, it is expected that project proponents will be responsible for the costs. The project proponents will be responsible to demonstrate any residual benefits to the Alberta market. Upon demonstration of these benefits, commensurate sharing of costs may occur with load customers in Alberta.

The regulated framework for transmission should also allow development of “merchant” transmission lines, involving Direct Current (DC) lines to export power over long distances and across borders on a fee-for-service basis. Open access to merchant transmission lines should be available to market participants subject to an auction or other transparent process.
Electricity Policy Framework (June 6, 2005)

1. Executive Summary

Short Term Adequacy:… (page 3)
After extensive consultation with stakeholders during one-on-one meetings and STA working group discussions, the common stakeholder view was that enhancing existing market designs and rules would address STA concerns and that implementation of a day-ahead market (DAM) design was not necessary at this time. The Department agrees with this conclusion. As such, the Department recommends refinements to the wholesale market structure that will improve supply visibility and stability for the ISO and thereby enhance system reliability and price fidelity. Specific recommended refinements address:

- Treatment of imports in the same manner as intra-Alberta generators

Other Market Issues:… (page 4)
Interties: To the extent possible, industry suppliers with import capacity should be treated the same as intra-Alberta generators. The Department, therefore, recommends that all imports be required to offer energy and allowed to set Pool price if they are able to respond to an intra-hour energy market dispatch.

4.3.3. LTA [Long Term Adequacy] Options

Other Adequacy Tools (page 32)
Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning power market as they support reliability, price stability, generation development and continued economic growth in Alberta. Albertans benefit from these interconnections by having the ability to import or export power as needed.

The Transmission Policy and Regulation provides certain direction regarding interties. The ISO is required to create long term plans including consideration of interties and is also provided with direction to reinforce the transmission system internal to Alberta so that existing intertie capacity is restored to its design path rating. The Transmission Policy and Regulation also provides a framework for the development of privately funded merchant transmission lines for import and export of electric energy. This approach is starting to generate significant interest in the industry.

Additional intertie capacity may provide an alternative to address long term adequacy. For example, a transmission adequacy criteria could specify that sufficient intertie capacity be available to allow transfers of up to 20 per cent of system peak load (i.e. ~ 2000 MW). This could allow greater exports from Alberta which could stimulate generation development in the province and also enhance system adequacy. Such exports could be recallable in times of system supply shortages.

4.3.4. Recommendations (page 34-35)

Recommendation: The Department considers that strong interconnection capacity with neighbouring jurisdictions may, in the long term, contribute to address or significantly mitigate long term adequacy concerns for Alberta. The Department recommends that the ISO, as part of its obligation to assess and ensure reliability, consider and evaluate the merits of additional intertie capacity, including new interconnections, in its long term plans. Additional intertie
capacity and interconnections may allow greater exports from Alberta which could stimulate
generation development in the province and also enhance system adequacy. Such exports
could be recallable in times of system supply shortages.

4.4.3. Interties (pages 38-39)

Export Capacity

Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning
power market as they support reliability, price stability, generation development and continued
economic growth in Alberta. Albertans benefit from these interconnections by having the ability
to import or export power as needed.

As noted previously, the Transmission Policy and Regulation provide certain direction regarding
interties. The ISO is required to create long term plans including consideration of interties and is
also provided with direction to reinforce the transmission system internal to Alberta so that
existing intertie capacity is restored to its design path rating. The Transmission Policy and
Regulation also provides a framework for the development of privately funded merchant
transmission lines for import and export of electric energy.

Recommendations

The Department recommends that the ISO evaluate additional tie-line capacity with
neighbouring systems in its 20-year Transmission Outlook documents and plans. Supporting
export capability of surplus energy could stimulate generation development in the province
which would directly enhance system adequacy and reliability. Exports would be recallable in
times of system supply shortages.

Seams Issues

There are a number of seams issues with neighbouring jurisdictions that have been and
continue to be examined, the most pressing of which for several stakeholders is the impact
imports have on Pool price.

Currently, import bids are required to be offered in at $0/MW·h and do not set Pool prices. This
requirement was imposed because imports are unable to respond within the hour to the SMP,
due to inter regional scheduling practices. Allowing imports to set price would better reflect the
true cost of energy. This issue could be addressed by simply allowing imports to set price when
they are the marginal unit, and to be price-takers when not the marginal unit. One potential
concern for this option is that it could give importers greater pricing flexibility and an unfair
advantage over in-province generation. A second concern is the system operator’s ability to
forecast, for scheduling and dispatch purposes, whether imports or exports would be in merit.

Recommendations

To the extent possible, imports are to be treated the same as intra Alberta generators:

• Owners of “firm transmission” must offer energy on a day ahead basis – this energy will be
taken into account in the AESO’s reliability assessment and must be delivered if issued an
energy dispatch
• Energy to be delivered on “non-firm transmission” may be offered up to T-2 and must be
delivered if issued an energy dispatch
• Imports will be allowed to set Pool price if they are able to respond to an intra hour energy market dispatch – in the near term this will mean that importers wishing to set Pool price will have to make arrangements for intra Alberta generation to accept an energy market dispatch during the delivery hour
• Imports are subject to the T-2 “lockdown” for price restatements
• Imports with firm transmission must respond to a commitment dispatch.
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%\(^{252}\), and included an updated STS rate schedule in its proposed rate schedules.\(^{253}\)

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.\(^{254}\)

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.\(^{255}\)

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.\(^{256}\) In Decision 2005-096, the Board encouraged the AESO to continue stakeholder

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\(^{252}\) Ex. 005, Application, Section 4, Table 4.0.1, p. 2
\(^{253}\) Ex. 008, Application, Section 7, p. 26
\(^{254}\) From the AESO website, 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.
\(^{255}\) AESO Argument, p 47
\(^{256}\) 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.\textsuperscript{257}

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.\textsuperscript{258} Minor revisions were subsequently made to the proposed XTS rate schedule in an AESO errata filing.\textsuperscript{259}

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.\textsuperscript{260} 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.\textsuperscript{261}

TCE expressed concerns about issues of consistency with other jurisdictions (seams issues)\textsuperscript{262} 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.

\textsuperscript{257} Ex. 005, Section 4.8 of the Application, p. 44; Decision 2005-096, p. 35
\textsuperscript{258} Ex. 005, Section 4.8.1 of the Application, page 46, Ex 008, Section 7 of the Application, pp. 12-13 of 129
\textsuperscript{259} Ex. 382, AESO Errata Filing no. 2 dated May 10, 2007
\textsuperscript{260} Tr. Vol. 3, p. 601
\textsuperscript{261} Ex. 242, TCE Evidence, p. 46, cited in Powerex Argument at p. 26
\textsuperscript{262} Powerex-TCE 8 and Powerex-TCE 9; see also Exhibit 126, TCE.AEOSO-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 expert service on the British Columbia- Alberta intertie line.263 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

263 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.\(^{264}\)

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.\(^{265}\)

Subsection 8(1)(g) of the 2004 *Transmission Regulation*,\(^{266}\) 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

\(^{264}\) TAU Reply Argument, p. 4  
\(^{265}\) Decision 2005-096, p. 35.  
\(^{266}\) *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). 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.

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.

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267 Ex. H-008
268 Decision 2005-096, p. 37
269 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 it intends to use rate XTS contract sign-ups as a signal or trigger for transmission system planning purposes, 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 test 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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270 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, 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, 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. 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.

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271 Powerex Argument, p. 25  
272 Ex 008, Application, section 7, rate schedules at pages 12, 14, 16 of 129  
273 TAU Reply Argument, p. 4  
274 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.\(^{275}\) The fixed and variable component of each DTS rate component was then examined to determine which costs should be included in export rates.\(^{276}\)

### 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.\(^{277}\)

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.\(^{278}\) The resulting costs attributable to Rate XOS 1 Hour and to Rate XOS 1 Month were presented in the Application.\(^{279}\)

TCE submitted extensive evidence on export rates.\(^{280}\) 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.\(^{281}\)

The AESO also noted TCE suggested 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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\(^{275}\) Ex. 005, Application, Section 4, Table 4.8.2, p. 46  
\(^{276}\) Ex. 005, Application, Section 4, Table 4.8.1, p. 45  
\(^{277}\) Ex. 005, Application, Section 4, p. 48, lines 43-44  
\(^{278}\) Ex. 005, Application, Section 4, Tables 4.8.4 and 4.8.5, pp. 48-49  
\(^{279}\) Ex. 005, Application, Section 4, p. 49  
\(^{280}\) TCE Evidence, pp. 33-46 & Appendix H  
\(^{281}\) TCE Evidence, p. 36, Figure 4  
\(^{282}\) 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\(^{283}\) but that the AESO’s calculation of the reserve charge to opportunity service appears to involve embedded costs.\(^{284}\) TCE noted the AESO explained that significant reserves were required even if there are no opportunity sales.\(^{285}\)

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.\(^{286}\)

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\(^{287}\) 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.\(^{288}\) 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.\(^{289}\) Powerex accepted the recommendations of TCE with respect to XOS 1 Month.

\(^{283}\) Ex. 242, TCE Evidence, Appendix F, p. 5, lines 31-33
\(^{284}\) Ex. 005, Application, Section 4, Table 4.7.1, p. 40 and TCE Evidence (Ex. 242) p. 42
\(^{285}\) Ex. H-022, where AESO’s Operating Policy and Procedure 402 is discussed.
\(^{286}\) TCE Argument, pp. 55-56, also Ex 242, TCE Evidence, p. 42
\(^{287}\) Ex. H-022, Undertaking No. 3
\(^{288}\) Powerex Argument, p. 33
\(^{289}\) 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\textsuperscript{290} for the variable costs of connecting to the system are based upon the AESO’s proposed classification of costs using the A&E method.\textsuperscript{291} 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.\textsuperscript{292} 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.\textsuperscript{293} 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.\textsuperscript{294} 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,\textsuperscript{295} will in the Board’s view result in recovery of the incremental costs incurred to provide opportunity service.

\textsuperscript{290} Ex. 005, Application, Section 4, p. 49, Tables 4.8.4 and 4.8.5
\textsuperscript{291} Ex. 005, Application, Section 4, p. 48, item (a) and p. 46, Table 4.8.2
\textsuperscript{292} AESO calculation based on 50\% energy related, if reduce to 18\% calculation is (.18/.50)*$2.42<$1
\textsuperscript{293} Ex. 005, Application, Section 4, Table 4.7.1, p. 40
\textsuperscript{294} TCE evidence, Figure 4, p. 36
\textsuperscript{295} 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 is below the current EOS Rate. However, as stated above, opportunity rates should also reflect value of service.

In its evidence, TCE proposed 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, 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. 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.

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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296 Ex. 242, TCE Evidence, Figure 4, p. 36
297 Ex. 242, TCE Evidence, Figure 4, p. 36
298 Application, Schedule 5.1, Black Start only $2.8 million of $644.9 million revenue requirement allocated to DTS
299 Ex. 005, Application, Section 4.9, p. 50
300 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. 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.

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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301 Ex. 006
302 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. 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.

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. 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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303 Tr. Vol. 3, p. 722, lines 11-20
304 Tr. Vol. 3, p. 725, lines 6-25, p. 726, and p. 727, lines 1-8
305 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 EnCan.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.306

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 panel307 and the TCE panel308 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.309

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307 Tr. Vol. 3 p. 723 lines 10-25 and p. 724
308 Tr. Vol. 6, p. 1198 lines 10-25 to p. 1204 lines 1-6
309 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. 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.

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 Boards 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. 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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310 Tr. Vol. 6, pp. 1209-1210
311 Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13-19
312 Decision 2005-96, pp. 57-58 (Direction 13A)
The Board notes that the largest single element in the proposed FDS rate is the allocation of TMR costs. The Board agrees with BCH that the AESO has not provided a sufficient basis for this charge. In particular, the Board does not consider that there is sufficient evidence that the AESO has considered the real value of Fort Nelson generation to Alberta customers.

The Board also notes the proposed $455,000 charge for contribution to fixed costs. The Board does not consider this charge has been justified on the basis of a reasonable allocation of actual costs.

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. the postage stamp rate for bulk wires costs;
2. the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;
3. the postage stamp rate for the AESO’s own costs and other industry costs; and
4. the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.

The Board does not consider it necessary to charge a POD related cost as BCH provides its own facilities. Correspondingly, BCH should not be eligible for the PSC credit in the future as it will not be charged for POD services.

The STS service provided to Fort Nelson should continue to be charged at the full postage stamp rate plus a losses charge to be determined by the AESO, in the same manner as it would for an Alberta generator.

Both DTS and STS services provided to Fort Nelson should continue to be subject to the usual deferral account treatment, similar to that of any other customer.

The Board considers the above will result in just and reasonable charges for service to Fort Nelson. The Board also considers that this provides a reasonable template for the provision of other inter-provincial services as well. The AESO’s proposed tariff treatment of Fort Nelson is denied and the AESO is directed to continue to provide DTS and STS services to Fort Nelson on the basis set out above and the refiling should demonstrate this treatment.

5.8 Export Rates

5.8.1 Firm Export/Import Rates

In Decision 2002-099, the Transmission Administrator’s (TA) Congestion Management Decision, the Board directed the TA to “…further investigate whether a firm import/export service could be offered over the existing B.C. Tie with a level of “firmness” acceptable to prospective import/export customers”.

In response to this directive, the AESO submitted that it began contacting its customers active in importing and exporting in the spring and summer of 2004. On September 23, 2004, the AESO published an Alberta Import/Export Tariff discussion paper to broaden consultation with stakeholders. The paper was presented at a stakeholder conference on October 6, 2004 followed by written comments from six stakeholders. Discussion was also held at a December 3, 2004
stakeholder workshop, with a follow-up *Directions and Plans* discussion paper published on December 9, 2004.

The AESO submitted that the key considerations resulting from this examination of firm export and import services were:

- Firm export tariffs would add a new option for participants and may enhance investment opportunities for new supplies. However, at present there appears to be little demand for a firm export option and deferral of further detailed development until after the Wholesale Market Review appears appropriate.
- Deferring development of a firm export tariff will also allow careful examination of issues such that the introduction avoids or minimizes negative impacts on the market.
- Firm import tariffs appear inconsistent with the transmission cost allocation principles in the Transmission Regulation and would disadvantage imports compared to domestic supplies.

As a result of these considerations, the AESO proposed the following in its Application:

(a) Continued development of a firm export tariff with the objective of including such a tariff in the AESO’s 2007 General Tariff Application (expected to be filed in late 2005 or early 2006); and,

(b) No further action to be taken on establishing a firm import tariff at this time.

During the proceeding, a number of parties took the position that the AESO was not responding to the Board’s directives from Decision 2002-099 in a timely fashion, and requested that the Board order the AESO to implement firm import/export rates as part of its Decision in this proceeding. The parties further considered that the AESO was ignoring directives from the *Transmission Regulation* to implement firm import and export rates.

TCE presented and testified to evidence in the proceeding concerning a form of firm export service which it submitted that the AESO could implement in a timely fashion. By way of argument, the AESO submitted that TCE’s proposal provided for a different level of firm service than was normally accepted as firm in the utility industry. The AESO further noted that TCE agreed as well under cross that its proposal might be considered as a lower level of firm service.

The AESO further noted that TCE’s proposal for a deferral account mechanism in support of its proposed firm export service was lacking in detail, and thus TCE’s proposal should be set aside until a full stakeholder process could occur on this proposal.

Finally the AESO submitted that the position taken by a number of parties in the proceeding that the AESO was not responding to the urging of industry to develop firm import and export rates had taken it by surprise. The AESO further noted that both IPSAA and ATCO Power had failed to provide comments on its Import/Export discussion paper when given the opportunity. The AESO did submit in argument that, if further stakeholder consultation did identify the urgency suggested by parties in this proceeding, it would proceed to develop a new proposal for import and export tariffs prior to or in conjunction with its 2007 application.

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55 See Argument in Chief and Reply Argument of TCE, IPSSA, TAU, ATCO Power.
56 T1919
TCE also took issue with the AESO’s calculation of Available Transfer Capacity (ATC). TCE suggested that the AESO should include all of the Calgary area generation in its calculations. The AESO responded that, while the export market required hourly commitments, the Alberta market required generator response on a minute by minute basis, and suggested that the reliability of the Alberta system could be jeopardized by deeming this generation to be available. The AESO further submitted, by way of exhibit\footnote{Exhibit 30(13)}, that export ATC was to be governed as an AESO rule, per Subsection 20(1) of the EUA, and therefore was not subject to Board ruling.

FIRM submitted that WECC definitions of ATC unique to import and export services should be considered in the Alberta market calculation of ATC. FIRM further submitted that the application of a firm DTS rate to export without proper ratchet provisions and investment levels could result in preferential treatment inadvertently being part of an export tariff. FIRM supported the AESO position for further stakeholder consultation in the development of firm import and export tariffs, as well as agreeing with the AESO that its calculation of ATC not include all Calgary area generation.

IPCAA submitted that all TFO customers end up paying for TMR costs related to firm export tariffs, and as such, DTS customers would not be kept whole if a firm export tariff were developed. IPCAA further submitted that TCE had not established sufficient urgency that further stakeholder consultation on firm export service should be ignored. IPCAA noted\footnote{Page 28, IPCAA Argument in Chief} TCE’s acknowledgement that not all stakeholders who will be impacted by the development of firm export tariffs had been contacted, and further noted\footnote{Page 29, IPCAA Argument in Chief} TCE’s admission that its firm export tariff proposals were still maturing. IPCAA further considered that the Board should direct the AESO to consult with stakeholders prior to the end of 2005 concerning any changes to the definition of ATC in Southern Alberta.

The Board considers that the Transmission Regulation supercedes many of the principles it established in Decision 2002-099. As such, it is not clear to the Board that certain directives concerning import and export rates from that Decision can be still be considered to be in effect. The Board notes that even TCE acknowledged during cross\footnote{T1983, lines 14-20} that a number of principles from Decision 2002-099 would have to be modified because of the Transmission Regulation, including, for example, changes caused by the shifting of cost recovery from a 50/50 DTS/STS recovery to a 100% recovery from DTS customers.

The Board has reviewed Subsection 8(1)(g) of the Transmission Regulation, dealing with the restoration of the inter-tie 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.

\footnote{Exhibit 30(13)} \footnote{Page 28, IPCAA Argument in Chief} \footnote{Page 29, IPCAA Argument in Chief} \footnote{T1983, lines 14-20}
The Board further considers that TCE’s proposal for firm import and export rates is deficient at this point in time in that the Board considers there to be a potential for cross subsidization to occur due to the lack of detail currently available concerning TCE’s proposal for a TMR deferral account mechanism.

Therefore the Board will not require the AESO to include firm import or export rates as part of its 2006 tariff. The Board however, does encourage the AESO to continue the stakeholder discussions with interested parties on a go forward basis towards the potential development of firm import and export rates.

With respect to the calculation of ATC, the Board is in agreement with the AESO that this calculation does not fall under the Board’s jurisdiction, but is, instead, subject to AESO rules. The Board will therefore not provide any ruling concerning the AESO’s calculation of ATC, but again urges further consultation with stakeholders.

5.8.2 Generator Remedial Action Scheme (GRAS)

The AESO noted in its application that a GRAS is used to restore and maintain power system frequency at acceptable levels.

The AESO noted that it was approached by a group of stakeholders interested in increasing export capability during the fourth quarter of 2004. The AESO further noted that as part of these discussions, it and the stakeholder group had evaluated operating practices that might enable additional export opportunities consistent with the requirements of the Transmission Regulation.

The AESO noted that one potential action given prominent consideration in its discussions with the stakeholders interested in export capacity expansion was a proposal to re-establish a GRAS similar to the Keephills Remedial Action Scheme that was in place prior to 2000. The AESO submitted that a feasibility analysis of GRAS is currently underway and that the use of GRAS to increase export capability would be explored when this feasibility analysis was complete.

ATCO Power submitted that the AESO has an obligation to pursue measures such as GRAS in order to enhance export capability. ATCO Power submitted that the AESO should not be permitted to "kink the hose" by withholding export tariffs and export capacity, thereby stranding surplus generation in Alberta. Further, ATCO Power noted that Subsection 8(1)(g) of the Transmission Regulation requires the AESO to make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside of Alberta can import and export electricity on a continuous basis, at or near the transmission facility's path rating.

IPPSA also suggested that a GRAS was required in order to reflect true market conditions. IPPSA submitted that the AESO had GRAS capability at the Keephills PPA, and that GRAS equipment could be installed in a matter of months. As such, IPPSA recommended that the Board should direct the AESO to implement a GRAS as soon as it had completed its technical studies. TCE also submitted that the Keephills GRAS capability should be restored as soon as possible. In its evidence, TCE noted that the Alberta Government Transmission Development Policy paper indicated that the cost of RAS arrangements required to allow the interties to function as designed should be allocated to load.\(^{61}\)

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\(^{61}\) TCE Evidence (Exhibit 23-010) page 12 of 42, Citing Alberta Government Transmission Development Policy Paper (Exhibit 30-027), page 9
FIRM noted that as GRAS is associated with exports rather than imports, the costs of GRAS should be recovered completely from firm export loads as well as export opportunity loads to the extent that such loads are responsible for GRAS costs.

The Board agrees with parties that GRAS may be pursued by the AESO as part of its strategy to ensure that interconnections with jurisdictions outside Alberta can import and export electricity on a continuous basis at or near the path rating of the interconnections. The Board does not agree, however, that Subsection 8(1)(g) of the Transmission Regulation may be interpreted in a manner that should cause the Board to direct the AESO to re-implement a generator remedial action scheme. The Board considers that direction to the AESO in the Transmission Regulation to restore the capacity of the intertie does not supersede the AESO’s duty to ensure a safe, reliable system. As such, the Board considers that the AESO must be satisfied that system safety and reliability is not compromised by a decision to implement a program such as GRAS. The Board is comforted by the ongoing efforts of the AESO to ensure that GRAS may be implemented reliably before any steps are taken to implement it.

In any event, the Board is reluctant within the context of a tariff application proceeding to, in effect, over-ride the AESO’s technical judgement on the measures that the AESO needs to take to fulfill its mandate to ensure the reliable operation of the transmission system. In this regard, the Board expects that the implementation of GRAS would generally be affected through the development of an operating policy and, as such, would fall under the ambit of an AESO rule pursuant to Section 20 of the EUA. Accordingly, the Board notes that concerns about the appropriateness of an AESO operating policy should generally be brought before the Board through the complaint mechanism described in Section 25 of the EUA.

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.

Accordingly, if the AESO were to enter into a RAS arrangement during the term of the Tariff, the Board would expect that the costs of this arrangement would be allocated to DTS customers. The Board may consider other cost allocation arrangements only after the rated design capability of the existing intertie facilities has been restored.

5.8.3 Opportunity Import and Export Rates

The Board notes that the AESO has proposed minor changes to its opportunity import and export rates to accommodate the provisions of the Transmission Regulation that requires DTS customers to pay for 100% of load.

The Board notes that no parties commented against the AESO’s proposed modification to these two rates. The Board has reviewed the proposed modifications and considers them to be in compliance with the changes required by the Transmission Regulation as noted above and therefore approves the AESO’s proposed modifications to these rates. The Board directs the AESO to update its proposals accordingly in its refiling, using the values which result from the Board’s recommended rate design, as discussed in section 5.5 of this Decision.
Fortis also disputed AltaLink’s assertion that the AESO did not object to AltaLink’s proposal, noting the following comments of Mr. Millar:\footnote{Transcript Volume 1, pages 184-186}

The entire structure of contributions in aid of construction is really set up, first and foremost, to ensure overall proper cost accountability among the customers. And from the AESO’s perspective, a distribution company is another customer, and we would expect the same tariff provisions to apply and, in fact, are required by this Board to treat a distribution point of delivery the same as an industrial point of delivery for investment and contribution purposes.

So we see that as being the primary issue. Distribution companies generally have fairly large held contributions in aid of construction that are reducing their net rate base. The fact that they may be obliged to pay a contribution that increases the rate base I don’t think is necessarily a conceptual problem we have.

The contribution then may go on to reduce the transmission facility owner’s net rate base. They obviously still own the asset, and it’s sitting in the transmission facility owner’s fixed capital records, but the calculation of net base rate would be reduced.

And if that is causing some perceived loss to the transmission facility owner, I think there are other ways of addressing that issue, and that should be an issue the transmission facility owner should bring before the Board in their own rate application.

I don’t think it would be appropriate to adjust the contribution policy to achieve, I’ll say, a bad outcome on the signal it’s sending customers for the sake of addressing the issue in the transmission facility owner’s, in their books, and that it issue -- if to the extent it is an issue -- can properly and probably be better addressed head on than by trying to ensure that contributions aren’t paid in the first place.

The Board has considered the comments of AltaLink and finds that the AltaLink proposal would create unnecessary changes to current practice and administrative complexity, largely to effect an increase in TFO rate base. The AltaLink proposal is denied.

\subsection{7.4 Merchant Transmission Interconnections}

This issue was first raised by TCE in its intervener evidence. TCE noted that Section 15(6) of the \textit{Transmission Regulation} stated:

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.

TCE maintained the Application does not provide the rates and T&Cs contemplated by Section 15(6). These rates and terms and conditions were needed by transmission developers, including merchant transmission developers, to determine the cost of service for use of an interconnection with the AIES.\footnote{TCE.AESO-229(c)}

TCE recommended the following principles in respect of transmission facilities seeking to export or import electricity:
1. An interconnection tariff will only be based on the use of that portion of the AIES that is reasonably attributed to the merchant transmission line (i.e. on a point to point basis).

2. An interconnection tariff respecting the use of the AIES will be based on the AIES transmission lines actually used to provide the service. Such a tariff will not be based on theoretical transmission lines that could be built to provide a direct connection to the merchant transmission line from the generators supplying energy over the lines.

3. Costs of the transmission facilities involved in providing service to the merchant transmission line, including facility specific losses, will be shared with other users of the same facilities based on a pro rata sharing of those lines using peak loads for each user.

4. Costs recovered from merchant transmission developers will be based on the actual cost of service of the transmission facilities being shared by other AIES Customers using the same transmission facilities.

5. All costs of a transmission line built solely to interconnect a generator with the merchant transmission line, and that provides no benefit to the AIES, would be charged to the merchant transmission developer.

In argument, the AESO stated that, other than that provided by TCE, there was limited evidence or discussion on merchant transmission issues or principles. The issue of tariffs for merchant transactions was closely linked to tariffs for exports and imports over existing interconnections. The AESO stated a broad consultation with stakeholders on the combined issues had not occurred.

The AESO supported the continued examination of merchant transmission interconnection issues, such as those raised by TCE, through consultation. The AESO further requested that the Board refrain from taking a view on principles at this time. The AESO believed that principles, tariffs, and terms and conditions could be provided as part of the AESO 2007 GTA.

In reply, TCE maintained that the AESO had not complied with Subsection 31(1) of the Transmission Regulation which required the tariff to include all matters required by the regulation and included those provisions contemplated in Subsection 15(6). TCE submitted that, if the Board agreed with TCE’s interpretation of these sections in the Transmission Regulation, then the Board should not accept the proposal that the principles, tariffs, and terms and conditions be delayed until the AESO 2007 GTA. The more compliant approach would be to adopt or modify TCE’s recommended principles\textsuperscript{115} and then direct the AESO to prepare a set of tariffs, terms and conditions that reflect those principles as soon as reasonably practical.

The Board has considered the provisions referenced and, while it agrees with TCE that the AESO proposed tariff must contain provisions that include costs for use of the interconnected electric system for import or export, the Board finds that this provision does not require the development of tariff rate terms and conditions for merchant use.

As the proposed tariff includes provisions for the use of the AEIS for import and export services, the Board considers the provision in Subsection 15(6) to be satisfied. The Board appreciates the

\textsuperscript{115} Exhibit 23-010, TransCanada Written Direct Evidence, page 29, line 20 to page 30, line 11
Dear Stakeholder:

Re: Update to Discussion and Request for Comments on Potential Changes to AESO Deferral Account Reconciliation Process

As a result of further consideration of potential changes to its deferral account reconciliation process, the AESO has updated its initial proposals as discussed below. The AESO invites stakeholders to provide comments on the revised proposals using the accompanying updated form (rather than the earlier form provided on November 12). The deadline for comments has been extended to Friday, December 4, 2009.

On November 12, 2009, the AESO posted on its website a letter discussing proposals planned to be included in either or both of the AESO’s 2010 tariff application (to be filed later this year) or the AESO’s 2009 deferral account reconciliation application (to be filed in March or April of 2010). On November 19, 2009, the AESO met with stakeholders to further review these proposals and discuss additional related information. The discussion letter, presentation, and other consultation information are available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff.

The AESO’s updated proposals reflect information included in the AESO’s presentation to stakeholders and are discussed in more detail below.

1 Proposed Changes to Riders B and C

As discussed in the November 12, 2009, discussion letter, the AESO proposes to delete Rider B and file the attached draft of Rider C (which includes some minor wording changes) for approval as part of its 2010 tariff application. The AESO invites stakeholders to provide comments on the draft Rider C.

2 AUC Comments in 2008 Deferral Account Reconciliation Decision

During the November 19, 2009, consultation meeting, the AESO discussed what it considers the disadvantages of requesting approval of deferral account reconciliation process changes in a tariff application, as suggested by the Alberta Utilities Commission in paragraphs 56-57 of Decision 2009-191 on the AESO’s 2008 deferral account reconciliation:

November 26, 2009

Deferral Account Riders B and C Working Group Members
AESO Stakeholders
The AESO invited stakeholders to provide comments on potential changes to the AESO deferral account reconciliation process, which were discussed in more detail in a stakeholder meeting at the AESO office on November 19, 2009, and in a letter posted on the AESO website on November 26, 2009. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the Electric Utilities Act, regulations, and decisions of the Alberta Utilities Commission.

Request for Comments: November 26, 2009
Consultation Period: November 26 through December 4, 2009

Written comments were provided by the following parties by December 4, 2009:
- Cities of Red Deer and Lethbridge
- EPCOR Distribution and Transmission Inc.
- FortisAlberta Inc.
- TransAlta
- TransCanada

The comments as provided by each stakeholder are attached. The AESO will provide responses to comment, where necessary, in the near future.
Decerber 4, 2009

John Martin  
Director, Tariff Applications  
Alberta Electric System Operator  
2500, 330 – 5th Avenue SW  
Calgary, AB T2P 0L4

Dear Mr. Martin

SUBJECT: AESO Deferral Account Reconciliation Process

Further to your request, the Cities of Red Deer and Lethbridge offer their comments on the AESO’s deferral account discussion papers dated November 19th and 26th. The Cities primary interest on this matter is to reduce the volatility and magnitude of deferral account variances, which currently cause unpredictable swings in Rider C charges and additional reconciliations many months (and even years) after the fact. In this regard, the AESO’s ‘roll-up’ approach to deferral account reconciliation (as per the November 12th discussion paper) does not address the Cities’ concerns, nor does it reduce the Cities’ administrative burden. The Cities agree with the general conclusion of the AESO’s November 26th discussion paper that it would be prudent to maintain status quo while pursuing other initiatives to minimize future deferral account balances.

The Cities also acknowledge that the AESO’s November 26th discussion paper requests feedback on the possible elimination of Rider B as well as the content of the AESO’s next GTA. While the Cities support the principle of maintaining a financially viable ISO, they are unable to comment further as the AESO is uniquely qualified to determine whether Rider B is required for this purpose. Furthermore, the Cities consider it inappropriate to formally comment on the content of the AESO’s next GTA without the benefit of reviewing the AESO’s proposals in the context of a complete draft application.

The Cities are appreciative of the AESO’s efforts to improve its tariff and associated processes. Should you have any questions, feel free to contact me at (403) 781-7690.

Sincerely,

Nigel Chymko  
President

cc: Otto Lenz  
Ligong Gan
The AESO invites stakeholders to provide comments on the following potential changes to the AESO deferral account reconciliation process, which were discussed in more detail in a stakeholder meeting at the AESO office on November 19, 2009, and in a letter posted on the AESO website on November 26, 2009. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the *Electric Utilities Act*, regulations, and decisions of the Alberta Utilities Commission.

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<tr>
<th>Request for Comments:</th>
<th>November 26, 2009</th>
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<tr>
<td>Consultation Period:</td>
<td>November 26 through December 4, 2009</td>
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Comments From: EPCOR Distribution and Transmission Inc.
Date: December 4, 2009
Contact: Pat Wong
Phone: 780-412-3361
E-mail: pwong@epcor.ca

**1 Proposed Changes to Riders B and C**

<table>
<thead>
<tr>
<th>The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application.</th>
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<tr>
<td>☒ Support</td>
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<td>☐ Oppose</td>
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<td>☐ Indifferent</td>
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Reasons for Stakeholder Position: Rider B appears to be obsolete.

**2 AUC Comments in 2008 Deferral Account Reconciliation Decision**

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<tr>
<th>The AESO proposes to include in its 2010 tariff application a general discussion of the information provided in the November 26, 2009, letter but no specific requests for approval of deferral account reconciliation process changes.</th>
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**3 Changes to Deferral Account Reconciliation Process**

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<tr>
<th>(a) The AESO no longer considers the proposed “termination and roll-up” approach described in its November 12, 2009, discussion letter to be practical.</th>
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<tr>
<td>☒ Support</td>
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<td>☐ Oppose</td>
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<td>☐ Indifferent</td>
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Reasons for Stakeholder Position: The termination and roll-up approach does not reduce any work for the AESO.
(b) The AESO proposes to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate.

Reasons for Stakeholder Position: Supported by stakeholders.

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<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
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### 4 Other Alternative Processes

(a) The AESO considers implementation of an alternative process to be impractical as the balances in the AESO’s deferral accounts continue to remain relatively large and volatile, due in large part to variances between operating reserve costs and revenues (which both vary with pool price).

Reasons for Stakeholder Position: For the reasons cited by the AESO.

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<tr>
<th>Support</th>
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(b) The AESO suggests it may be reasonable to defer further changes to the deferral account reconciliation process until the proposed operating reserve charge is reviewed in the AESO’s 2010 tariff application.

Reasons for Stakeholder Position:

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<th>Support</th>
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<th>Indifferent</th>
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(c) The AESO proposes to continue to meet with stakeholders during preparation of its annual deferral account reconciliation applications, and will re-assess the conclusions in its November 26 letter at those meetings.

Reasons for Stakeholder Position:

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<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
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</table>

### Additional Comments

The AESO should continue to explore the viability of having its DAR models /methodologies approved by the AUC, then filing the calculations for information only.

Please return this form with your comments by December 4, 2009, to:

Ghaz Marinho  
Regulatory Services  
E-mail: ghaz.marinho@aeso.ca  
Phone: 403-539-2474  
Fax: 403-539-2949
Updated Discussion of Changes to AESO Deferral Account Reconciliation Process
AEO 2010 Tariff Consultation
November 26, 2009 Request for Comments — Stakeholder Comment Form

The AESO invites stakeholders to provide comments on the following potential changes to the AESO deferral account reconciliation process, which were discussed in more detail in a stakeholder meeting at the AESO office on November 19, 2009, and in a letter posted on the AESO website on November 26, 2009. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the Electric Utilities Act, regulations, and decisions of the Alberta Utilities Commission.

Request for Comments: November 26, 2009
Consultation Period: November 26 through December 4, 2009

Comments From: FortisAlberta Inc.
Date: December 1, 2009
Contact: Miles Stroh
Phone: (403) 514-4229
E-mail: Miles.Stroh@fortisalberta.com

1 Proposed Changes to Riders B and C
The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application.

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Reasons for Stakeholder Position:
FortisAlberta supports the deletion of Rider B. Rider C is able to perform the functions of Rider B and Rider B has not been used since 2003.

FortisAlberta specifically supports the AESO’s proposal to release the Rider C forecast 30 days in advance of it becoming effective because this would allow FortisAlberta to better forecast costs to be incurred through its deferral rider in the upcoming quarter.

2 AUC Comments in 2008 Deferral Account Reconciliation Decision
The AESO proposes to include in its 2010 tariff application a general discussion of the information provided in the November 26, 2009, letter but no specific requests for approval of deferral account reconciliation process changes.

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Reasons for Stakeholder Position:

3 Changes to Deferral Account Reconciliation Process
(a) The AESO no longer considers the proposed “termination and roll-up” approach described in its November 12, 2009, discussion letter to be practical.

<table>
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Reasons for Stakeholder Position:
(b) The AESO proposes to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate.

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<th>Support</th>
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<th>Indifferent</th>
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Reasons for Stakeholder Position:
As per the presentation presented by the AESO on November 19, 2009, the full reconciliation would provide for a more precise and accurate reconciliation.

### 4 Other Alternative Processes

(a) The AESO considers implementation of an alternative process to be impractical as the balances in the AESO's deferral accounts continue to remain relatively large and volatile, due in large part to variances between operating reserve costs and revenues (which both vary with pool price).

<table>
<thead>
<tr>
<th></th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:
Please refer to reason in 3(b) above.

(b) The AESO suggests it may be reasonable to defer further changes to the deferral account reconciliation process until the proposed operating reserve charge is reviewed in the AESO's 2010 tariff application.

<table>
<thead>
<tr>
<th></th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

(c) The AESO proposes to continue to meet with stakeholders during preparation of its annual deferral account reconciliation applications, and will re-assess the conclusions in its November 26 letter at those meetings.

<table>
<thead>
<tr>
<th></th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

**Additional Comments**

Please return this form with your comments by December 4, 2009, to:

Ghaz Marinho  
Regulatory Services  
E-mail: ghaz.marinho@aeso.ca  
Phone: 403-539-2474  
Fax: 403-539-2949
The AESO invites stakeholders to provide comments on the following potential changes to the AESO deferral account reconciliation process, which were discussed in more detail in a stakeholder meeting at the AESO office on November 19, 2009, and in a letter posted on the AESO website on November 26, 2009. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the *Electric Utilities Act*, regulations, and decisions of the Alberta Utilities Commission.

### Request for Comments: November 26, 2009

**Consultation Period:** November 26 through December 4, 2009

**Comments From:** TransAlta

**Date:** December 3, 2009

**Contact:** Bob Smith

**Phone:** 403-267-7119

**E-mail:** bob_smith@transalta.com

### 1 Proposed Changes to Riders B and C

<table>
<thead>
<tr>
<th>The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application.</th>
<th>X Support</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oppose</td>
</tr>
<tr>
<td></td>
<td>Indifferent</td>
</tr>
</tbody>
</table>

**Reasons for Stakeholder Position:**

### 2 AUC Comments in 2008 Deferral Account Reconciliation Decision

<table>
<thead>
<tr>
<th>The AESO proposes to include in its 2010 tariff application a general discussion of the information provided in the November 26, 2009, letter but no specific requests for approval of deferral account reconciliation process changes.</th>
<th>X Support</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oppose</td>
</tr>
<tr>
<td></td>
<td>Indifferent</td>
</tr>
</tbody>
</table>

**Reasons for Stakeholder Position:** TransAlta agrees with the AESO that deferral account process changes are more efficiently addressed in the deferral account reconciliation application.

### 3 Changes to Deferral Account Reconciliation Process

<table>
<thead>
<tr>
<th>The AESO no longer considers the proposed “termination and roll-up” approach described in its November 12, 2009, discussion letter to be practical.</th>
<th>X Support</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oppose</td>
</tr>
<tr>
<td></td>
<td>Indifferent</td>
</tr>
</tbody>
</table>

**Reasons for Stakeholder Position:**

TransAlta was okay with the proposal the AESO made for termination and roll-up; however, if the AESO prefers to continue the current multiple year retrospective deferral account reconciliations in annual applications that works for TransAlta as well. TransAlta is most
concerned that the AESO continues to provide the information by settlement point.

<table>
<thead>
<tr>
<th>(b)</th>
<th>The AESO proposes to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>X Support ☐ Oppose ☐ Indifferent</td>
</tr>
</tbody>
</table>

Reasons for Stakeholder Position: See (a) above.

### 4 Other Alternative Processes

<table>
<thead>
<tr>
<th>(a)</th>
<th>The AESO considers implementation of an alternative process to be impractical as the balances in the AESO’s deferral accounts continue to remain relatively large and volatile, due in large part to variances between operating reserve costs and revenues (which both vary with pool price).</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>X Support ☐ Oppose ☐ Indifferent</td>
</tr>
</tbody>
</table>

Reasons for Stakeholder Position: TransAlta accepts the AESO conclusion that deferral accounts continue to remain relatively large and volatile.

<table>
<thead>
<tr>
<th>(b)</th>
<th>The AESO suggests it may be reasonable to defer further changes to the deferral account reconciliation process until the proposed operating reserve charge is reviewed in the AESO’s 2010 tariff application.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>☐ Support ☐ Oppose ☒ Indifferent</td>
</tr>
</tbody>
</table>

Reasons for Stakeholder Position: TransAlta is not sure of the what evidence the AESO has to make this conclusion but since the AESO has a defined process that works there does not appear to be any reason to make changes at this time.

<table>
<thead>
<tr>
<th>(c)</th>
<th>The AESO proposes to continue to meet with stakeholders during preparation of its annual deferral account reconciliation applications, and will re-assess the conclusions in its November 26 letter at those meetings.</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
</tbody>
</table>

Reasons for Stakeholder Position: 

### Additional Comments

Please return this form with your comments by December 4, 2009, to:

Ghaz Marinho  
Regulatory Services  
E-mail: ghaz.marinho@aeso.ca  
Phone: 403-539-2474  
Fax: 403-539-2949
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Request for Comments: November 26, 2009
Consultation Period: November 26 through December 4, 2009

Comments From: TransCanada
Date: December 4, 2009
Contact: Chris Best
Phone: 403-920-2081
E-mail: chris_best@transcanada.com

1 Proposed Changes to Riders B and C

| The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application. | Support | Oppose | Indifferent |

Reasons for Stakeholder Position: TransCanada is indifferent to the removal of Rider B.

TransCanada supports the proposed Rider C, with the exception of the newly added clause 3(3) which indicates no interest will be charged or credited for deferral account amounts. In the past, the AUC and AEUB have taken different approaches to the payment of interest in different circumstances (see AUC Decision 2009-010 and EUB Decisions 2003-033 & 2003-054). TransCanada believes parties should retain the right to recover interest payments should the circumstances warrant. TransCanada recommends the AESO consider the following revision to Term 3(3):

The ISO will not *typically* add or deduct interest to or from amounts recovered or refunded through Rider C or through a deferral account reconciliation application *unless the Commission orders otherwise in appropriate circumstances*. (changes in bold and italics).

2 AUC Comments in 2008 Deferral Account Reconciliation Decision

| The AESO proposes to include in its 2010 tariff application a general discussion of the information provided in the November 26, 2009, letter but no specific requests for approval of deferral account reconciliation process changes. | Support | Oppose | Indifferent |

Reasons for Stakeholder Position:
TransCanada supports the Deferral Account Reconciliation (DAR) process remaining separate from the General Tariff Application process. This will allow the DAR to be considered in more detail and more quickly.

3 Changes to Deferral Account Reconciliation Process

(a) The AESO no longer considers the proposed “termination and roll-up” approach described in its November 12, 2009, discussion letter to be practical.  

Reasons for Stakeholder Position:

TransCanada is of the view that the “termination and roll-up” approach adds little value while creating greater risk of increased workload and potential for errors if terminated years are later reopened. The “termination and roll-up approach” will also add to the complexity and cost when customers reconcile their billing information with that used by the AESO in deferral account reconciliations.

(b) The AESO proposes to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate.

Reasons for Stakeholder Position:

The current full DAR process, systems and timing have only been in place for one year (2008). TransCanada would like to see it utilized for at least two more years (2009 & 2010) before any material changes are made, such as moving to a prospective approach. Consideration of more substantive changes to the DAR process will be more appropriate when the AESO’s proposed revisions to recovery of operating reserve costs have been approved and implemented and have demonstrated a reduction in the amount of the Deferral Account amounts to be reconciled.

4 Other Alternative Processes

(a) The AESO considers implementation of an alternative process to be impractical as the balances in the AESO’s deferral accounts continue to remain relatively large and volatile, due in large part to variances between operating reserve costs and revenues (which both vary with pool price).

Reasons for Stakeholder Position:

See 3(b) comments
(b) The AESO suggests it may be reasonable to defer further changes to the deferral account reconciliation process until the proposed operating reserve charge is reviewed in the AESO's 2010 tariff application.

Reasons for Stakeholder Position:

See 3(b) comments

(c) The AESO proposes to continue to meet with stakeholders during preparation of its annual deferral account reconciliation applications, and will re-assess the conclusions in its November 26 letter at those meetings.

Reasons for Stakeholder Position: Ongoing discussion on these changes is appropriate.

**Additional Comments**

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Comments From:
Date:
Contact:
Phone:
E-mail:

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### 1. Proposed Changes to Riders B and C

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Reasons for Stakeholder Position:

---

### 2. AUC Comments in 2008 Deferral Account Reconciliation Decision

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Reasons for Stakeholder Position:

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### 3. Changes to Deferral Account Reconciliation Process

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Reasons for Stakeholder Position:
(b) The AESO proposes to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate.

Reasons for Stakeholder Position:

4 Other Alternative Processes

(a) The AESO considers implementation of an alternative process to be impractical as the balances in the AESO’s deferral accounts continue to remain relatively large and volatile, due in large part to variances between operating reserve costs and revenues (which both vary with pool price).

Reasons for Stakeholder Position:

(b) The AESO suggests it may be reasonable to defer further changes to the deferral account reconciliation process until the proposed operating reserve charge is reviewed in the AESO’s 2010 tariff application.

Reasons for Stakeholder Position:

(c) The AESO proposes to continue to meet with stakeholders during preparation of its annual deferral account reconciliation applications, and will re-assess the conclusions in its November 26 letter at those meetings.

Reasons for Stakeholder Position:

Additional Comments

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Ghaz Marinho
Regulatory Services
E-mail: ghaz.marinho@aeso.ca
Phone: 403-539-2474
Fax: 403-539-2949
Potential Changes to AESO Deferral Account Reconciliation Process

John Martin, Regulatory
Carol Moline and Roxanne Moeskops, Accounting
November 19, 2009 — Calgary

Agenda

• Introduction and background (slides 1-5)
• Proposed changes to Riders B and C (slides 6-8)
• Commission comments in Decision 2009-191 (slides 9-13)
• Termination of full reconciliations (slides 14-18)
• Allocation of “rolled-up” deferral account balances (slides 19-25)
• Full re-reconciliation of terminated year (slides 26-29)
• Next steps and discussion (slides 30-35)
Meeting Objectives

- Determine approach to addressing changes in deferral account reconciliation process in 2010 tariff application
- Understanding of AESO proposal for terminating full deferral account reconciliations and allocated balances in terminated years
- Discussion of triggers for full re-reconciliations of terminating years and approach to such re-reconciliations
- Responses to questions about proposed changes

Introduction and Background

- On April 9, 2009, the AESO filed a comprehensive deferral account reconciliation application for 2008
  - First reconciliation for 2008
  - Third reconciliation for 2003
  - Reconciliations of adjustments for 2002 and 2001
- The application included all transactions accounted for up to December 31, 2008 that related to 2008 and prior years
- Application followed model of 2004-2007 application
  - Sections for each year discussed cost variances, revenue variances, and deferral account balances
Introduction and Background (cont’d)

- 12 appendices included extensive reports showing allocation of deferral account balances to customers
  - Over 1,600 pages in appendices
  - About 200 pages for each full reconciliation year
- Decision 2009-074 released on June 3, 2009 approved the interim distribution of balances in the 2008 application
- Only five information requests asked
- Decision 2009-191 released on October 29, 2009 approved the 2008 application on a final basis, as filed
  - Commission expressed concern about repeated re-reconciliations of deferral account years already considered by the Commission

Proposed Deletion of Rider B

- AESO proposes to delete Working Capital Deficiency/Surplus Rider B as part of 2010 tariff application
  - Rider B has not been used since before 2003
  - Rider B provides no useful value beyond that already provided through Rider C
- Deletion of Rider B would occur in conjunction with change to hourly allocation of operating reserve costs
  - Effectively would eliminate most volatile component of deferral accounts
Proposed Changes to Rider C

• Rider C will be posted 30 days in advance of it becoming effective
  – Provides advance notice to market participants
• Rider C will continue to be calculated to restore deferral account balances to zero over next calendar quarter
• Rider C will continue to be calculated as a $/MWh amount determined by rate component
  – Change to hourly allocation of operating reserve costs will effectively eliminate most volatile component

Proposed Changes to Rider C (cont’d)

• Rider C will only include transactions since January 1 of the calendar year in which Rider C will apply
  – Q1 Rider C will therefore exclude prior-year balances
  – Prior-year balances will be addressed in deferral account reconciliation based on transactions as of December 31
  – Q2, Q3, and Q4 will include any prior-year balances resulting from transactions after December 31
• The AESO will not add or deduct interest from amounts recovered or refunded through Rider C or through a deferral account reconciliation application
Commission Comments on Repeated Re-Reconciliations

- “…because deferral account processes and the riders… have a bearing on the ultimate allocation of tariff costs to individual AESO customers, go forward changes in these processes should generally be addressed in the context of an AESO GTA.” [paragraph 56, bolding added]

- “…concern about the number of times that additional reconciliation is required in respect of deferral account years that have already been considered by the Commission in the context of prior deferral account reconciliation applications. The Commission urges AESO to be mindful of this concern as it considers its redesign of deferral account reconciliation processes and associated rate riders for its forthcoming GTA.” [paragraph 57, bolding added]

Addressing Deferral Account Process Changes in GTA

- Previous deferral account process changes have been addressed in deferral account reconciliation applications
  - Production year treatment of losses, allocation of losses on volumes times pool price, and monthly allocation of balances in 2000-2002 DAR application
  - Production year treatment of all revenue and costs in 2003 DAR application
  - Discussion of prospective rider methodology in compliance filing resulting from DAR Decision 2003-099
  - Full reconciliations of multiple years in 2004-2007 DAR application

- Impact of deferral account process changes unknown until implemented in a deferral account reconciliation
  - May be difficult for parties to assess whether their “rights may be directly and adversely affected” by changes
Addressing Deferral Account Process Changes in GTA (cont’d)

- Decision on 2010 tariff application expected in late 2010 or early 2011
  - 2009 deferral account reconciliation planned to be filed in March-April 2010 (prior to tariff application decision)
  - Computer program changes for 2010 deferral account reconciliation need to be started in October-November of 2010 (prior to tariff application decision)
  - If deferral account process changes must be approved as part of 2010 tariff application process, they likely cannot be implemented until 2011 deferral account reconciliation (planned to be filed in March-April 2012)

Addressing Deferral Account Process Changes in GTA (cont’d)

- Requesting deferral account process changes in 2009 reconciliation application could result in implementation for 2009 and 2010 deferral account reconciliations
  - Risk of requested changes not being approved and subsequent requirement for refiling of 2009 application
  - General stakeholder support required to mitigate risk
- AESO proposes to generally discuss process changes but not request approval in 2010 tariff application, and to use the proposed process to prepare its 2009 deferral account reconciliation and request approval in that proceeding
  - Subject to general stakeholder support
Comparison of Approaches to Requesting Approval for Changes

<table>
<thead>
<tr>
<th>Request Approval for Changes in Tariff Application</th>
<th>Implement and Request Approval for Changes in DAR Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impact of changes not known at time of tariff application</td>
<td>Impact of changes included in application</td>
</tr>
<tr>
<td>Effective for 2011 deferral account reconciliation</td>
<td>Effective for 2009 deferral account reconciliation</td>
</tr>
<tr>
<td>No risk of refiling as process will be approved before implementation</td>
<td>Risk of refiling if changes not approved as proposed</td>
</tr>
</tbody>
</table>

Possible Approach for Termination of Full Reconciliations

- Full reconciliations of a production year include the allocation of deferral account balances to customers based on detailed deferral account allocation methodology
  - By customer revenue
  - By volumes times pool price (for losses, up to 2005)
- To terminate full reconciliation for a year, non-material adjustments related to the terminated year would be rolled up into the oldest year for which a full reconciliation is being completed
- AESO considers that full reconciliations should occur for at least three years
  - 2007, 2008, and 2009 for the 2009 DAR application
### Illustration of Termination of Full Reconciliations

<table>
<thead>
<tr>
<th>Production Year</th>
<th>2009 DAR Application</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Treatment (for DTS rate class)</td>
</tr>
<tr>
<td>2009</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2008</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2007</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2006</td>
<td>Roll Up to 2007</td>
</tr>
<tr>
<td>2005</td>
<td></td>
</tr>
<tr>
<td>2004</td>
<td></td>
</tr>
<tr>
<td>2003</td>
<td></td>
</tr>
<tr>
<td>2002</td>
<td></td>
</tr>
<tr>
<td>2001</td>
<td></td>
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</tbody>
</table>

### Preliminary Deferral Account Balances by Year: DTS and STS

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<tbody>
<tr>
<td>Interconnection</td>
<td>378.7</td>
<td>(.08)</td>
<td>(.3)</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Losses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating Reserve</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Voltage Control</td>
<td>36.4</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other System Support</td>
<td>6.2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Revenue</strong></td>
<td><strong>487.9</strong></td>
<td><strong>(0.9)</strong></td>
<td><strong>(0.3)</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Wires</td>
<td>(396.5)</td>
<td>(2.9)</td>
<td>2.8</td>
<td>1.5</td>
<td>(0.1)</td>
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<tr>
<td>Ancillary Services</td>
<td>(107.0)</td>
<td>(1.3)</td>
<td>(0.5)</td>
<td>-</td>
<td>(0.2)</td>
<td>(0.3)</td>
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<tr>
<td>Losses</td>
<td></td>
<td></td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Other Industry</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>General &amp; Admin</td>
<td>(41.9)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td><strong>(555.9)</strong></td>
<td><strong>(4.1)</strong></td>
<td><strong>2.3</strong></td>
<td>1.5</td>
<td>(0.3)</td>
<td>(0.3)</td>
</tr>
<tr>
<td>Surplus (Shortfall)</td>
<td>(68.0)</td>
<td>(5.0)</td>
<td>2.0</td>
<td>1.5</td>
<td>(0.3)</td>
<td>(0.3)</td>
</tr>
</tbody>
</table>

No transactions for pre-2004 years
Amounts as of September 2009
### Reconciled and Rolled-Up Amounts by Rate Component: DTS and STS

#### Surplus (Shortfall), $ 000

<table>
<thead>
<tr>
<th>Year</th>
<th>Inter-connection</th>
<th>Losses</th>
<th>Operating Reserve</th>
<th>Voltage Control</th>
<th>OSS Services</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>(25,980)</td>
<td></td>
<td>(3,461)</td>
<td>5,692</td>
<td>351</td>
<td>(23,399)</td>
</tr>
<tr>
<td>2008</td>
<td>(3,655)</td>
<td>50</td>
<td>(1,363)</td>
<td>(18)</td>
<td>(4,986)</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>2,512</td>
<td>(14)</td>
<td>(491)</td>
<td>(13)</td>
<td>1,995</td>
<td></td>
</tr>
</tbody>
</table>

#### Rolled-Up Years

<table>
<thead>
<tr>
<th>Year</th>
<th>Surplus (Shortfall), $ 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>1,535</td>
</tr>
<tr>
<td>2005</td>
<td>(75)</td>
</tr>
<tr>
<td>2004</td>
<td>(50)</td>
</tr>
</tbody>
</table>

#### Total

<table>
<thead>
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<tr>
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<td>351</td>
<td>(23,399)</td>
</tr>
<tr>
<td>2008</td>
<td>(3,655)</td>
<td>50</td>
<td>(1,363)</td>
<td>(18)</td>
<td>(4,986)</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>2,512</td>
<td>(14)</td>
<td>(491)</td>
<td>(13)</td>
<td>1,995</td>
<td></td>
</tr>
</tbody>
</table>

#### Rolled-Up Years

<table>
<thead>
<tr>
<th>Year</th>
<th>Surplus (Shortfall), $ 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>1,535</td>
</tr>
<tr>
<td>2005</td>
<td>(44)</td>
</tr>
<tr>
<td>2004</td>
<td>(29)</td>
</tr>
</tbody>
</table>

#### Total

<table>
<thead>
<tr>
<th>Year</th>
<th>Surplus (Shortfall), $ 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>1,535</td>
</tr>
<tr>
<td>2005</td>
<td>(44)</td>
</tr>
<tr>
<td>2004</td>
<td>(29)</td>
</tr>
</tbody>
</table>

No transactions for pre-2004 years
Amounts as of September 2009
Roll-Up of Non-Material Transactions: DTS Rate Class

- Costs allocated to DTS rate class would be rolled up into the oldest year for which a full reconciliation is being completed.
- Revenue and cost adjustments would be rolled up into the same production month in which they originally occurred, but in the year into which they are being rolled up.
  - Addresses potential seasonal revenue patterns.
  - Alternative would be to allocate annual aggregate of revenue and cost adjustments equally over each month in the year into which they are being rolled up.

Reconciled and Rolled-Up Amounts by Rate Component: STS Only

<table>
<thead>
<tr>
<th>Year</th>
<th>Inter-connection</th>
<th>Losses</th>
<th>Operating Reserve</th>
<th>Voltage Control</th>
<th>OSS Services</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- No transactions for pre-2004 years.
- Amounts as of September 2009.
Roll-Up of Non-Material Transactions: STS Rate Class

- Costs allocated to STS rate class (before 2006) would be rolled up into prospective Rider E at the time of approval
- Rider E became effective January 1, 2006, and relates only to transmission system losses
  - Rider E applies to generators, demand opportunity service, exports, and imports
- Pre-2006 STS adjustments may relate to interconnection, operating reserves, and other system support service rate components
  - Efficient and practical approach to address non-material adjustments

Distribution of Allocation Changes Due to “Roll-Up” Approach

Allocation Changes Due to Roll-Up of $8 Million in One Month

- $0 – $5,000 Charge: 37%
- $5,000 – $10,000 Charge: 4%
- $10,000 – $25,000 Charge: 6%
- $25,000 – $50,000 Charge: 2%
- > $50,000 Charge: 1%

Percentage of Customer-Month Combinations
Distribution of Allocation Changes Due to “Roll-Up” Approach (cont’d)

Thresholds for Materiality of Adjustments

- **Cost adjustments** are material when the deferral account balance exceeds ±1% of the AESO’s forecast annual revenue requirement for the production year
  - By rate component (interconnection charge, operating reserve change, etc.),
  - In aggregate for a year, or
  - In aggregate for all rolled-up years
  - For 2006: ±1% of $759.0 million or ±$7.6 million

- **Revenue adjustments** are material when, in the AESO’s opinion, a full reconciliation is needed to correctly address the impact of a customer revenue adjustment on deferral account allocations to that customer
Recent Rider E Balances

<table>
<thead>
<tr>
<th>Rider E Balance</th>
<th>2009</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q4</td>
<td>$1.1 million over collected</td>
<td>$10.0 million over collected</td>
</tr>
<tr>
<td>Q3</td>
<td>$0.1 million under collected</td>
<td>$1.1 million over collected</td>
</tr>
<tr>
<td>Q2</td>
<td>$1.5 million over collected</td>
<td>$1.3 million over collected</td>
</tr>
<tr>
<td>Q1</td>
<td>$1.4 million over collected</td>
<td>$2.4 million over collected</td>
</tr>
</tbody>
</table>

Example of Full Re-Reconciliation of Terminated Year

- Material wires cost adjustment occurred in 2010 related to 2005 production year (after 2005 was terminated in 2009 DAR application)
  - No material adjustments occurred in 2010 that relate to 2004, 2006, or 2007
- Accurate deferral account balances would be re-created for full reconciliation of 2005
  - 2005 DTS adjustments that were rolled up into 2007 in the 2009 application are now removed from 2008 (as 2007 no longer has a full reconciliation) and reconciled in 2005 full reconciliation
  - 2005 STS adjustments that were incorporated into Rider E in 2010 (resulting from the 2009 application) are removed from current year Rider E and reconciled in 2005 full reconciliation
Example of Full Re-Reconciliation of Terminated Year (cont’d)

<table>
<thead>
<tr>
<th>Production Year</th>
<th>2009 DAR Application</th>
<th>2010 DAR Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>-</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2009</td>
<td>Full Reconciliation</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2008</td>
<td>Full Reconciliation</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2007</td>
<td>Full Reconciliation</td>
<td>Roll Up to 2008</td>
</tr>
<tr>
<td>2006</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2005</td>
<td>Roll Up to 2007</td>
<td>Full Reconciliation</td>
</tr>
<tr>
<td>2004</td>
<td></td>
<td>Roll Up to 2008</td>
</tr>
</tbody>
</table>

Disclosure of Non-Material Transactions

- The AESO proposes that detailed variance explanations not be provided for rolled-up years in a deferral account reconciliation application
  - Explanations would be provided for large adjustments
- Annual deferral account summary information will be provided for rolled-up years
- Annual deferral account tables for full reconciliations will detail rolled-up year amounts included
## Example Summary Information Provided for Rolled-Up Year

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Demand Transmission Service</th>
<th>Recorded Revenue (a)</th>
<th>Recorded Costs (b)</th>
<th>Over (Under) Collection (c)=(a)+(b)</th>
<th>Prior Deferral Account Collections (Refunds) (d)</th>
<th>Rider C Prior DAR (e)</th>
<th>Roll-Up to 2007 (f)=Σ(c)(e)</th>
<th>(g)=(f)÷(b)</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Interconnection</td>
<td>$467.0 ($470.1)</td>
<td>($3.2)</td>
<td>$14.5 ($10.4)</td>
<td>$0.9</td>
<td>0.2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Operating Reserve</td>
<td>173.5 (185.3)</td>
<td>(11.9)</td>
<td>13.3</td>
<td>0.6</td>
<td>1.9</td>
<td>1.1%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Voltage Control</td>
<td>52.3 (39.3)</td>
<td>13.0</td>
<td>(12.4)</td>
<td>(0.5)</td>
<td>0.0</td>
<td>0.0%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Other System Support</td>
<td>7.9 (7.6)</td>
<td>0.4</td>
<td>(0.3)</td>
<td>(1.0)</td>
<td>(0.9)</td>
<td>(11.7%)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Total DTS</td>
<td>$700.6 ($702.3)</td>
<td>($1.7)</td>
<td>$15.1 ($11.3)</td>
<td>$2.0</td>
<td>0.3%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes: Numbers may not add due to rounding.
¹ DAR means Deferral Account Reconciliation.

## Discussion

### Full Reconciliations
- Precision of allocation is high based on retrospective reconciliation
- Large amount of information filed
- Allocation is transparent and can be traced by customer
- Significant time and resource requirements of AESO
- AESO-developed software is reliable and accurate, can handle data, and can be updated annually

### Roll-Up Approach
- Less precise (year-over-year revenue change, addition of new customers, change in STS basis)
- Less information filed
- Allocation is less transparent
- Almost identical, but likely to increase if terminated year must be re-reconciled
- Software will need to be modified for roll-up of years
Discussion (cont’d)

<table>
<thead>
<tr>
<th>Full Reconciliations</th>
<th>Roll-Up Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methodology is well-established</td>
<td>New approach is more complex and will need to be tested</td>
</tr>
<tr>
<td></td>
<td>– materiality thresholds</td>
</tr>
<tr>
<td></td>
<td>– DTS allocation approach</td>
</tr>
<tr>
<td></td>
<td>– STS allocation approach</td>
</tr>
<tr>
<td></td>
<td>– re-reconciling terminated year</td>
</tr>
</tbody>
</table>

Alternatives?

- Change in approval request to reduce number of times that Commission must re-examine deferral account years that have already been considered by the Commission
  - Request approval of methodology and results for current deferral account year only (for example, for 2009 only)
  - All other years would be filed as appendix to current year application for information only, using the previously-approved methodology
  - Maintains precision and transparency of allocation
  - Results would be accepted unless intervener objected to results of reconciliation and AESO declined to address
- Could request approval of two or three years (rather than just one) with balance of years filed for information only
Next Steps

• Comments on consultation due on Friday, November 27
• 2010 tariff application to be filed in early December
• 2009 deferral account reconciliation application to be filed in March-April 2010
  – Using data cut-off date of December 31, 2009
  – Plan to request approval for immediate interim settlement of balances
• Q1 2010 Rider C would exclude 2009 year-end balances
  – Similar to Q1 2009 Rider C
  – Rider sheet would not change until approved as part of 2010 tariff application proceeding

Questions?
For More Information

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  Director, Tariff Applications
  Phone (403) 539-2465
  E-mail john.martin@aeso.ca

- Carol Moline
  Director, Accounting & Treasury
  Phone (403) 539-2504
  E-mail carol.moline@aeso.ca

- Consultation documents on AESO website at www.aeso.ca
  Tariff ► Current Consultations ► 2010 Tariff, in section for
  Deferral Account Riders B and C Working Group
November 12, 2009

Deferral Account Riders B and C Working Group Members
AESO Stakeholders

Dear Stakeholder:

Re: **Request for Comments on Potential Changes to AESO Deferral Account Reconciliation Process**

As discussed earlier this year during stakeholder consultation on the AESO’s 2008 deferral account reconciliation application and the AESO’s 2010 tariff application, the AESO has investigated changes to simplify and improve the efficiency of the deferral account reconciliation process. The AESO is now seeking comments from stakeholders on specific proposals for changes to the reconciliation process. The AESO invites stakeholders to provide comments by **Friday, November 27, 2009**, using the accompanying form.

The proposals will also be presented at a stakeholder meeting scheduled as follows:

- **Date:** Thursday, November 19, 2009
- **Time:** 1:30 – 4:30 PM
- **Place:** AESO Meeting Room 2539, 25th Floor
  330 – 5th Avenue SW, Calgary, Alberta
- **Refreshments:** Coffee, juice, snacks
- **RSVP:** By Tuesday, November 17, 2009 to Ghaz Marinho, 403-539-2474 or ghaz.marinho@aeso.ca

The following discussion summarizes the proposals which will be included in either or both of the AESO’s 2010 tariff application (to be filed later this year) or the AESO’s 2009 deferral account reconciliation application (to be filed in March or April of 2010).

**1 Proposed Changes to Riders B and C**

As discussed with stakeholders on the Deferral Account Riders B and C Working Group in the AESO’s 2010 tariff consultation, the AESO will propose the following changes to Riders B and C as part of its 2010 tariff application:

- **Rider B:**
  - Will be deleted from AESO tariff as it no longer serves a useful function

- **Rider C:**
  - Additional information will detail how quarterly values are determined
  - Only current year transactions will be included in Rider C (although such transactions may relate to a prior year)
  - Rider values will be released about a month before the start of a quarter
The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application. The AESO invites stakeholders to provide comments on the draft Rider C.

2 AUC Comments in 2008 Deferral Account Reconciliation Decision

In Decision 2009-191 on the AESO’s 2008 deferral account reconciliation, the Alberta Utilities Commission (Commission) commented (paragraphs 56-57, pages 10-11):

It remains the view of the Commission that because deferral account processes and the riders such as AESO’s current Rider B and Rider C have a bearing on the ultimate allocation of tariff costs to individual AESO customers, go forward changes in these processes should generally be addressed in the context of an AESO GTA.

Notwithstanding this finding, the Commission wishes to highlight its concern about the number of times that additional reconciliation is required in respect of deferral account years that have already been considered by the Commission in the context of prior deferral account reconciliation applications. The Commission urges AESO to be mindful of this concern as it considers its redesign of deferral account reconciliation processes and associated rate riders for its forthcoming GTA.

While the AESO does not object to addressing deferral account reconciliation process changes in its 2010 tariff application, the AESO notes that deferral account process changes have generally occurred in the context of deferral account reconciliation applications over the past several years. As well, changes proposed as part of the AESO’s 2009 deferral account reconciliation application could be implemented earlier than changes addressed through the 2010 tariff application (which would likely be approved late in 2010 and would therefore apply to the AESO’s 2010 deferral account reconciliation application).

The AESO proposes to include a general discussion of the deferral account reconciliation process described in this paper in its 2010 tariff application, and plans to use and request approval of the process in its 2009 deferral account reconciliation application. The AESO invites stakeholders to provide comments on this proposal, and specifically whether deferral account process changes can be more efficiently addressed in a tariff application or in a deferral account reconciliation application.

3 Termination of Full Reconciliations After Three Years

The AESO observes that its 2008 deferral account reconciliation application included full reconciliations for the six years from 2003 to 2008 plus reconciliations of adjustments for 2001 and 2002. The application contained over 1,600 pages of detail in multiple appendices. Yet the largest cost or revenue variance that occurred from 2001 to 2006 was ±$0.1 million, with only a $0.5 million net surplus over all six years. (These amounts exclude the removal of the redistribution of interest originally proposed in the AESO’s 2004-2007 deferral account reconciliation application.)

A similar scenario appears likely for the AESO’s 2009 deferral account reconciliation application. As of September 30, 2009, the years 2004, 2005, and 2006 contain deferral account balances of $0.3 million shortfall, $0.3 million shortfall, and $1.5 million surplus,
respectively, and total only $0.9 million net surplus. As well, no transactions have been recorded since the 2008 deferral account reconciliation for production years prior to 2004.

Given the small value of transactions that appear to arise more than three years after the deferral account year, the AESO proposes to provide full reconciliations for only the most recent three years in future deferral account reconciliation applications. For the 2009 application, the AESO proposes to provide full reconciliations for 2007, 2008, and 2009 only.

For all earlier production years to which transactions apply, those transactions will be “rolled up” into the oldest year for which a full reconciliation is being completed. For the 2009 application, the years 2004, 2005, and 2006 will be “rolled up” into 2007 (with the exception of amounts attributable to STS customers, as discussed below).

As no transactions relate to 2003 or prior years, the 2009 application will not include any presentation of years prior to 2004.

If similar results occur for the AESO’s 2010 and 2011 deferral account reconciliations, the treatment of transactions for each production year would be as show in Table 3-1.

Table 3-1 Treatment of Production Year Transactions With No Material Variances

<table>
<thead>
<tr>
<th>Year</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2010</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2009</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2008</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2007</td>
<td>Full reconciliation</td>
<td>Roll up into 2008</td>
<td>Roll up into 2009</td>
</tr>
<tr>
<td>2006</td>
<td>Roll up into 2007</td>
<td>Roll up into 2008</td>
<td>Roll up into 2009</td>
</tr>
<tr>
<td>2005</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2004</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2003</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2002</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2001</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

In summary, the AESO proposes to provide full reconciliations for only the most recent three years in future deferral account reconciliation applications, and to roll up non-material transactions for prior years into the oldest year for which a full reconciliation is being completed.

The above discussion describes the roll-up approach for deferral account balances for rate components attributable to DTS customers. A similar approach would be used for deferral account balances for rate components attributable to STS customers, but only up to 2005 which was the last year in which STS charges were subject to retrospective deferral account reconciliation. Effective January 1, 2006, transmission system losses (the only cost which continues to be attributed to STS customers) are no longer subject to retrospective reconciliation, but are recovered through the use of Calibration Factor Rider E.
As discussed above, small transactions related to 2004 and 2005 production years have accrued since the AESO’s 2008 deferral account reconciliation. However, as the AESO does not propose to complete a full reconciliation for any year prior to 2007, there would be no full reconciliation year into which these small balances could be rolled up.

As an alternative to continuing full reconciliations for 2005, the AESO proposes that non-material deferral account balances attributable to STS customers be carried forward and recovered or refunded through Calibration Factor Rider E. The AESO expects such amounts to be small compared to the cost of losses currently subject to Rider E.

To achieve the full efficiencies of a roll-up approach, the AESO proposes that detailed variance analysis not be provided for rolled-up years in its deferral account reconciliation applications. Only a deferral account summary table would be provided for rolled-up years, similar to those provided at the end of each production year section in the 2008 deferral account reconciliation application. An example table (for 2006, as filed in the AESO’s 2008 application) is provided in Table 3-2.

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Recorded Revenue</th>
<th>Recorded Costs</th>
<th>Over (Under) Prior Deferral Account Collections (Refunds)</th>
<th>Roll-Up to 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base Rate</td>
<td>(a)</td>
<td>(b)</td>
<td>(c)=(a)+(b)</td>
</tr>
<tr>
<td>1</td>
<td>Interconnection</td>
<td>$467.0</td>
<td>($470.1)</td>
<td>($3.2)</td>
</tr>
<tr>
<td>2</td>
<td>Operating Reserve</td>
<td>173.5</td>
<td>(185.3)</td>
<td>(11.9)</td>
</tr>
<tr>
<td>3</td>
<td>Voltage Control</td>
<td>52.3</td>
<td>(39.3)</td>
<td>13.0</td>
</tr>
<tr>
<td>4</td>
<td>Other System Support</td>
<td>7.9</td>
<td>(7.6)</td>
<td>0.4</td>
</tr>
<tr>
<td>5</td>
<td>Total DTS</td>
<td>$700.6</td>
<td>($702.3)</td>
<td>($1.7)</td>
</tr>
</tbody>
</table>

Notes: Numbers may not add due to rounding.

Although detailed variance explanations would generally not be required for production years in which no material variances occurred, the AESO would provide explanations for any large deferral account amounts which were rolled up into a later year.

The rolled-up amounts would also be listed, by year, in the deferral account tables in the year in which they were allocated.

In summary, the AESO proposes to provide in a deferral account reconciliation application only deferral account summary information for any year in which non-material amounts are rolled up into a later year.

4 Allocation of “Rolled-Up” Deferral Account Balances to the Same Production Month in Which They Originally Occurred

The AESO proposes that deferral account balances from a rolled-up year be allocated in the same production month in which they originally occurred, but in the year into which they are being rolled up. The AESO considers that roll-up by production month addresses potential concerns around seasonal revenue patterns of some customers that could affect allocation. Seasonal variability may be of greater importance than year-to-year variability for many DTS
customers, especially the distribution facility owners who are generally allocated the largest share of deferral account balances.

The AESO also notes that deferral account balances would be rolled up as separate cost and revenue amounts by rate component by month to determine the deferral account balances to be allocated to customers in the later full-reconciliation year. The rolled-up revenue amounts would not be included in the customer revenue amounts on which the deferral account balances are allocated, however, as doing so would impact the allocation of the larger amounts in the full-reconciliation year.

The AESO considers that the treatment of rolled-up STS deferral account balances through Rider E is essentially comparable to the allocation of rolled-up DTS amounts in the year into which they are rolled up.

In summary, the AESO proposes that deferral account balances from a rolled-up year be allocated in the same production month in which they originally occurred, but in the year into which they are being rolled up.

5 Full Re-Reconciliations of Terminated Year for Material Deferral Account Balance

The roll-up and allocation of deferral account balances for a production year would occur only when the balances for the year, both in total and by rate component, were not material. The AESO considers the materiality threshold discussed in 2005 during its deferral account reconciliation stakeholder consultation to remain reasonable, whereby balances would be considered material only if they exceeded — in total, by rate component, or by year — ±1% of the AESO’s forecast annual revenue requirement subject to retrospective reconciliation. For 2008, the materiality threshold would be ±$8.1 million; for 2009, it would be ±$8.7 million.

In addition to this deferral account balance materiality threshold, the AESO acknowledges that a customer revenue adjustment below this threshold may result in material reallocation of deferral account balances to that customer. However, it is impossible to accurately predict the impact of deferral account reallocation on a customer without completing a full reconciliation for all customers. As an alternative, the AESO proposes to examine individual customer revenue adjustments that have occurred in each rolled-up production year and report the largest such adjustment (as a percentage of total revenue for the customer) as part of its application. The AESO will also assess whether a full reconciliation is needed to correctly address the impact of the revenue adjustment on deferral account allocation to the customer. For this assessment, the AESO considers the ±$50,000 impact discussed during its 2005 stakeholder consultation to remain reasonable.

If adjustment transactions result in a deferral account balance exceeding the materiality threshold for a terminated year, or if the AESO assesses the impact of an individual customer revenue adjustment to be excessive, all transactions for that production year would be subject to a full reconciliation. The deferral account reconciliation application would therefore include all transactions for the relevant production year that have occurred since the last full reconciliation, even if they had been rolled up in one or more previous applications.

For example, if a material transaction for production year 2006 occurred during 2011, the deferral account reconciliations illustrated in Table 3-1 would instead appear as in Table 4-1. The full reconciliation for 2006 included in the 2011 application would include transactions for 2006 which had been rolled up in the 2009 and 2010 application.
In summary, the AESO proposes to provide a full re-reconciliation for any previously-terminated production year in which:

(a) deferral account balances — in total, by rate component, or by year — exceeds ±1% of the AESO’s forecast annual revenue requirement subject to retrospective reconciliation for the production year, or

(b) if, in the AESO’s opinion, a full reconciliation is needed to correctly address the impact of a customer revenue adjustment on deferral account allocation to that customer.

<table>
<thead>
<tr>
<th>Year</th>
<th>Deferral Account Reconciliation Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2009</td>
</tr>
<tr>
<td>2011</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2010</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2009</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2008</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2007</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2006</td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2005</td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2004</td>
<td>Roll into 2008</td>
</tr>
<tr>
<td>2003</td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2002</td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2001</td>
<td>Roll into 2007</td>
</tr>
</tbody>
</table>

6 Consultation Process

The AESO plans to present information on these topics to facilitate discussion at the November 19, 2009, stakeholder meeting, and invites stakeholder feedback by November 27 using the provided comment form.

This letter and all other printed information related to the Deferral Account Riders B and C Working Group and the 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca.

Sincerely,

[original signed by] John Martin
Director, Tariff Applications

attachment

cc: Carol Moline, Director, Accounting & Treasury, AESO
RIDER C
DEFERRAL ACCOUNT ADJUSTMENT RIDER

Applicability
1 Rider C applies to system access service provided under the following rates:
   (a) Demand Transmission Service Rate DTS;
   (b) Fort Nelson Transmission Service Rate FTS; and
   (c) Export Transmission Service Rate XTS.

Rider
2(1) Rider C recovers or refunds accumulated deferral account balances which are comprised of differences between revenues and costs incurred in providing system access service to customers.
(2) The ISO will determine Rider C for each calendar quarter as an additional $/MWh charge or credit that applies to each rate in subsection 1 above.
(3) The ISO will publish the Rider C charge or credit, including its calculation, on the ISO website at least thirty (30) calendar days prior to the beginning of the calendar quarter in which it will apply.
(4) The ISO will calculate the Rider C charge or credit as the sum of amounts, based on available recorded and forecast values, required to restore the deferral account balance to zero (0) over the following calendar quarter, or such longer period as determined by the ISO to minimize rate impact, in each of the following rate components:
   (a) interconnection charge;
   (b) operating reserve charge;
   (c) voltage control charge; and
   (d) other system support services charge
where revenues and costs are assigned to each rate component in accordance with the ISO tariff in effect during the period in which the revenue was collected or the cost was incurred.
(5) The Rider C calculation will include only transactions settled with the ISO that have occurred after January 1 of the calendar year in which the Rider C charge or credit will apply, although such transactions may involve amounts that relate to prior years.

Terms
3(1) The terms and conditions form part of this rider.
(2) Rider C amounts collected or refunded are subject to later adjustment in a deferral account reconciliation application filed with the Commission by the ISO.
(3) The ISO will not add or deduct interest will to or from amounts recovered or refunded through Rider C or through a deferral account reconciliation application.
Revision History

2009-11-12 Revised to reflect proposals in 2010 tariff application. Working draft, not released.
The AESO invites stakeholders to provide comments on the following potential changes to the AESO deferral account reconciliation process, which were discussed in more detail in a letter posted on the AESO website on November 12, 2009, and in a stakeholder meeting at the AESO office on November 19, 2009. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the Electric Utilities Act, regulations, and decisions of the Alberta Utilities Commission.

Request for Comments: November 12, 2009  
Consultation Period: November 12 through 27, 2009

## 1 Proposed Changes to Riders B and C

<table>
<thead>
<tr>
<th>The AESO proposes to delete Rider B and file the attached draft of Rider C for approval as part of its 2010 tariff application.</th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

## 2 AUC Comments in 2008 Deferral Account Reconciliation Decision

<table>
<thead>
<tr>
<th>The AESO proposes to include a general discussion of the deferral account reconciliation process described in this paper in its 2010 tariff application, and plans to use and request approval of the process in its 2009 deferral account reconciliation application.</th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

## 3 Termination of Full Reconciliations After Three Years

<table>
<thead>
<tr>
<th>In summary, the AESO proposes to provide full reconciliations for only the most recent three years in future deferral account reconciliation applications, and to roll up non-material transactions for prior years into the oldest year for which a full reconciliation is being completed.</th>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:
(b) As an alternative to continuing full reconciliations for 2005, the AESO proposes that non-material deferral account balances attributable to STS customers be carried forward and recovered or refunded through Calibration Factor Rider E.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

(c) In summary, the AESO proposes to provide in a deferral account reconciliation application only deferral account summary information for any year in which non-material amounts are rolled up into a later year.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

4 **Allocation of “Rolled-Up” Deferral Account Balances to the Same Production Month in Which They Originally Occurred**

In summary, the AESO proposes that deferral account balances from a rolled-up year be allocated in the same production month in which they originally occurred, but in the year into which they are being rolled up.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

5 **Full Re-Reconciliations of Terminated Year for Material Deferral Account Balance**

In summary, the AESO proposes to provide a full re-reconciliation for any previously-terminated production year in which:

(a) deferral account balances — in total, by rate component, or by year — exceeds ±1% of the AESO’s forecast annual revenue requirement subject to retrospective reconciliation for the production year, or

(b) if, in the AESO’s opinion, a full reconciliation is needed to correctly address the impact of a customer revenue adjustment on deferral account allocation to that customer.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

**Additional Comments**

Please return this form with your comments by November 27, 2009, to:

Ghaz Marinho  
Regulatory Services  
E-mail: ghaz.marinho@aeso.ca  
Phone: 403-539-2474  
Fax: 403-539-2949
Dear Stakeholder:

Re: **Potential Changes to Deferral Account Reconciliation Process**

As discussed in deferral account consultation and working group meetings earlier this year, the AESO has investigated changes to simplify and improve the efficiency of the preparation and review of deferral account reconciliation applications. The AESO invites you to a final consultation meeting on potential changes to the deferral account reconciliation process.

The consultation meeting will be held as follows:

- **Date:** Thursday, November 19, 2009
- **Time:** 1:30 – 4:30 PM
- **Place:** AESO Meeting Room 2539, 25th Floor, 330 – 5th Avenue SW, Calgary, Alberta
- **Refreshments:** Coffee, juice, snacks
- **RSVP:** By Tuesday, November 17, 2009 to Ghaz Marinho, 403-539-2474 or ghaz.marinho@aeso.ca

The AESO expects to discuss the following topics during the meeting:

(a) Rider C changes planned to be proposed in the AESO’s 2010 tariff application.

(b) Comments from the Alberta Utilities Commission in recent deferral account reconciliation decisions.

(c) Proposal to indefinitely terminate full reconciliations three years after the deferral account year and to "roll up" non-material transactions to the oldest year for which a full reconciliation is being filed.

(d) Proposal to allocate “rolled up” deferral account balances to the same production month in which they originally occurred, but in the destination year.

(e) Proposal to reopen a terminated year in the event a transaction resulted in a material deferral account balance.
The AESO plans to present information on these topics to facilitate discussion, and will post a brief discussion paper before the meeting if possible, including a comment form and invitation for additional stakeholder feedback.

This letter and all other printed information related to the Deferral Account Riders B and C Working Group and the 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Carol Moline, Director, Accounting & Treasury, AESO
### AESO

**2010 GTA Consultation on Riders B and C**

**Analysis of Prior Year Amounts in Rider C**

<table>
<thead>
<tr>
<th></th>
<th>Current Year</th>
<th>Volumes</th>
<th>Rider C</th>
<th>2004-2007 Application</th>
<th>Prior Year</th>
<th>Volumes</th>
<th>Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>GWh</td>
<td></td>
<td>(Shortfall)/Surplus $M</td>
<td>GWh</td>
<td></td>
<td>(Charge)/Refund $M</td>
</tr>
<tr>
<td>Q1 2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>(2.7)</td>
<td>14,659</td>
<td>(0.18)</td>
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<td>(0.6)</td>
<td>14,659</td>
<td>(0.04)</td>
</tr>
<tr>
<td>Other SSS</td>
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<td>14,659</td>
<td>0.03</td>
<td>n/a</td>
<td>0.8</td>
<td>14,659</td>
<td>0.05</td>
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<tr>
<td>Voltage Control</td>
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<td>0.72</td>
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<td>1.4</td>
<td>14,659</td>
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</tr>
<tr>
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<td>(1.5)</td>
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<tr>
<td>Q2 2008</td>
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</tr>
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<td>17.7</td>
<td>2.6</td>
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<td>0.19</td>
</tr>
<tr>
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<td>13,853</td>
<td>0.04</td>
<td>1.7</td>
<td>(1.1)</td>
<td>13,853</td>
<td>(0.08)</td>
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<td>Voltage Control</td>
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<td>0.22</td>
<td>(0.7)</td>
<td>1.7</td>
<td>13,853</td>
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</tr>
<tr>
<td><strong>Total</strong></td>
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<td>6.5</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Operating Reserves</td>
<td>(40.6)</td>
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<td>(3.03)</td>
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<td>13,415</td>
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<tr>
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<td>(1.77)</td>
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<td>(0.2)</td>
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<td>(0.02)</td>
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<tr>
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<td>1.7</td>
<td>0.0</td>
<td>13,415</td>
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<td>(0.7)</td>
<td>(0.1)</td>
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<td>(0.01)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
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<td>13,415</td>
<td>(4.41)</td>
<td>19.7</td>
<td>(0.3)</td>
<td>13,415</td>
<td>(0.02)</td>
</tr>
<tr>
<td>Q4 2008</td>
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<td></td>
</tr>
<tr>
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<tr>
<td>Other SSS</td>
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<td>n/a</td>
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<td>14,002</td>
<td>0.00</td>
</tr>
<tr>
<td>Voltage Control</td>
<td>(2.4)</td>
<td>14,002</td>
<td>(0.17)</td>
<td>n/a</td>
<td>(4.0)</td>
<td>14,002</td>
<td>(0.29)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>(65.5)</td>
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<td>(4.68)</td>
<td>n/a</td>
<td>(3.7)</td>
<td>14,002</td>
<td>(0.26)</td>
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<td>Q1 2009</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Operating Reserves</td>
<td>(24.7)</td>
<td>13,847</td>
<td>(1.78)</td>
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<td>(11.0)</td>
<td>13,847</td>
<td>(0.79)</td>
</tr>
<tr>
<td>Interconnection Charge</td>
<td>(9.1)</td>
<td>13,847</td>
<td>(0.66)</td>
<td>n/a</td>
<td>(5.7)</td>
<td>13,847</td>
<td>(0.41)</td>
</tr>
<tr>
<td>Other SSS</td>
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<td>0.04</td>
<td>n/a</td>
<td>0.2</td>
<td>13,847</td>
<td>0.01</td>
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<tr>
<td>Voltage Control</td>
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<td>(6.3)</td>
<td>13,847</td>
<td>(0.46)</td>
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<tr>
<td><strong>Total</strong></td>
<td>(30.3)</td>
<td>13,847</td>
<td>(2.19)</td>
<td>n/a</td>
<td>(22.8)</td>
<td>13,847</td>
<td>(1.65)</td>
</tr>
</tbody>
</table>

*Settled July 2008*

*Year end 2006, Pre-2007*

*Pre-2008*

*Year end 2008, Pre-2009*

June 26, 2009
AESO DTS Rider C - Summary by Rate ($/MWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>Quarter</th>
<th>Time</th>
<th>Rider C Interconn True-Up Rate ($/MWh)</th>
<th>Rider C Op Reserve True-Up Rate ($/MWh)</th>
<th>Rider C Losses/ Voltage Control True-Up Rate ($/MWh)</th>
<th>Rider C OSSS True-Up Rate ($/MWh)</th>
<th>Rider C Total ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td>1</td>
<td>2004Q1</td>
<td>0.62</td>
<td>-1.80</td>
<td>0.00</td>
<td>-0.04</td>
<td>-1.22</td>
</tr>
<tr>
<td>2004</td>
<td>2</td>
<td>2004Q2</td>
<td>2.15</td>
<td>-3.17</td>
<td>0.00</td>
<td>-0.03</td>
<td>-1.05</td>
</tr>
<tr>
<td>2004</td>
<td>3</td>
<td>2004Q3</td>
<td>0.79</td>
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<td>0.00</td>
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<td>-0.24</td>
</tr>
<tr>
<td>2004</td>
<td>4</td>
<td>2004Q4</td>
<td>0.30</td>
<td>-2.14</td>
<td>0.00</td>
<td>0.00</td>
<td>-1.84</td>
</tr>
<tr>
<td>2005</td>
<td>1</td>
<td>2005Q1</td>
<td>0.02</td>
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<td>0.00</td>
<td>-0.31</td>
</tr>
<tr>
<td>2005</td>
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<td>2005Q2</td>
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<td>0.39</td>
<td>0.00</td>
<td>0.01</td>
<td>0.50</td>
</tr>
<tr>
<td>2005</td>
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<td>2005Q3</td>
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</tr>
<tr>
<td>2005</td>
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<td>0.00</td>
<td>0.01</td>
<td>-0.04</td>
</tr>
<tr>
<td>2006</td>
<td>1</td>
<td>2006Q1</td>
<td>-0.04</td>
<td>-0.16</td>
<td>0.08</td>
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<tr>
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<td>2006</td>
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<td>1.07</td>
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</tr>
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<td>2007Q2</td>
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<td>-0.49</td>
<td>-0.04</td>
<td>0.66</td>
</tr>
<tr>
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<td>2007Q3</td>
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<tr>
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<td>-0.03</td>
<td>3.05</td>
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<td>0.67</td>
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</tr>
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<td>2008</td>
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<td>2008Q2</td>
<td>1.09</td>
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<td>-0.21</td>
<td>-0.05</td>
<td>-0.33</td>
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<td>1.77</td>
<td>3.02</td>
<td>-0.35</td>
<td>-0.03</td>
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</tr>
<tr>
<td>2008</td>
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<td>1.01</td>
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<td>0.17</td>
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<tr>
<td>2009</td>
<td>1</td>
<td>2009Q1</td>
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<td>1.79</td>
<td>-0.22</td>
<td>-0.04</td>
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<tr>
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<td>0.75</td>
<td>-0.41</td>
<td>-0.06</td>
<td>0.72</td>
</tr>
</tbody>
</table>

Note: "Losses" was used until January, 2006 and then was replaced by Voltage Control.

![AESO DTS Rider C Total](image_url)
June 5, 2009

Deferral Account Riders B and C Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Deferral Account Riders B and C Working Group

The first meeting of the Deferral Account Riders B and C Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 10:00 AM to 12:00 Noon
- **Date:** Monday, June 8, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, and pastries

This working group includes the following members:
- ADC: Colette Kearl
- ATCO Electric: Nick Palladino
- EPCOR: Stan Yee
- FortisAlberta: Monica Huynh
- IPCAA: Vittoria Bellissimo
- UCA: Rick Cowburn
- AESO: John Martin and Carol Moline

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   - **Time:** 10:00 AM

2. **Review agenda**
   - **Time:** 10:10 AM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
     - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
   - **Time:** 10:15 AM
A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for deferral account Riders B and C
- Please review the enclosed information before the meeting, if possible:
  (a) Riders B and C as currently approved in the AESO’s tariff
  (b) Calculation of AESO Quarterly Rider C for Q2 2009, as posted on the AESO website on March 31, 2009
  (c) Discussion on future deferral account matters (slides 36-52) from the AESO’s 2008 Deferral Account Reconciliation Application Consultation Meeting, held on March 3, 2009
- Is there other background that participants consider particularly relevant?

5 Discussion of potential changes to Rider B
- What is the purpose of Rider B?
- Is Rider B still needed? Will it ever be used?
- Are there better ways to accomplish Rider B’s purpose than through a rider?
- Should Rider B be revised, perhaps to be more similar to Rider C?

6 Discussion of potential changes to Rider C
- What is the purpose of Rider C?
- Should prior year balances be addressed through Rider C? In all quarters or just in the first quarter of the year?
- Should Rider C address forecast variances or just recorded variances?
- Is a quarterly recovery period the best approach for Rider C?
- Do all components of Rider C need to be treated in the same manner?
- Will Rider C always need to be subject to retrospective reconciliation? Can it move to a prospective approach similar to the losses calibration factor Rider E?

7 Other deferral account matters
- Is it appropriate for this group to consider changes to the reconciliation process, such as the “indefinite termination and roll-up” approach described in the slides?
- Are there other deferral account matters this working group should address?
- Are there other deferral account matters that should be addressed outside of this working group?

8 Follow-up required for next meeting
- Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s)

10 Adjourn

This agenda and all other printed information related to the Deferral Account Riders B and C Working Group are available on the AESO’s website at www.aeso.ca by following the path Tariff
Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Carol Moline at 403-539-2504 or carol.moline@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Carol Moline, Director, Accounting & Treasury, AESO
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
- Substations included in POD cost data set
- Inflation index to escalate POD cost data to 2010
- Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
- Respond to AUC directions on analysis of TFO O&M costs
- Determine if TFO O&M costs are energy-related
- Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
- Methodology to analyze and assess design of operating reserve charge
- Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
- Rate design principles for Fort Nelson and similar services
- Cost allocation approaches between BC and Alberta loads in the Rainbow Area
- Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
- Rate design principles for higher-priority export and import services
- Similarities and differences between domestic and intertie services
- Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
- Rate design principles for deferral account riders
- Practicality of improving allocation accuracy of deferral account riders
- Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.

- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
Rider B Working Capital Deficiency/Surplus Rider

Purpose: The Working Capital Deficiency/Surplus Rider is to recover unexpected increases in the AESO’s working capital deficiency or to refund unexpected surpluses of working capital.

Applicable to: Customers receiving service under the following Rate Schedules:
- DTS
- FTS

Effective: The rider will be invoked for the current Billing Period when, on the last Business Day of the current Billing Period:
- the AESO’s working capital balance either exceeds or falls short of the AESO’s annual average forecast by an amount equal to or greater than $7.0 Million.

Rate: A percentage increase or decrease, that when invoked will restore the AESO’s working capital deficiency to the AESO’s annual average forecast, applied to charges under the rate schedules listed above in the current Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule.
Rider C  Deferral Account Adjustment Rider

Purpose:  To recover or refund all accumulated deferral account balances.

Applicable to:  Customers receiving service under the following Rate Schedules:
   • DTS
   • FTS

Effective:  The rider is effective for all billing periods, effective January 1, 2006.

Rate:  An additional $/MWh charge or credit will be applied to each of the following:

DTS Rate Schedule
   • Interconnection Revenue Category
   • Operating Reserve Revenue Category
   • Voltage Control Revenue Category
   • Other Ancillary Services Revenue Category

FTS Rate Schedule
   • Interconnection Revenue Category
   • Operating Reserve Revenue Category
   • Voltage Control Revenue Category
   • Other Ancillary Services Revenue Category

to restore the deferral account balances to zero over the following calendar quarter or such longer period as determined by the AESO to minimize rate impact.

Terms:  The Terms and Conditions form part of this Rate Schedule.
AESO Quarterly Rider C
For Q2 2009

The following table provides a summary of the AESO's forecasted deferral account balance at June 30, 2009 and the Q2 2009 Rider C rate. The actual January to February 2009 and estimated deferral account balances for March 2009 and Q2 2009 are summarized as follows:

<table>
<thead>
<tr>
<th>($ millions)</th>
<th>Revenues Collected</th>
<th>(Costs Paid)</th>
<th>Variance February 2009 YTD</th>
<th>Rider 'C' Collected (Refunded) YTD February 2009</th>
<th>Total Variance - Overcollected/(Undercollected)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>January to February 2009 Actual</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating reserve charge (1)</td>
<td>23.0 (DTS) 27.2 (DTS)</td>
<td>(4.2) (DTS)</td>
<td>16.2 (DTS)</td>
<td>12.0 (DTS)</td>
<td></td>
</tr>
<tr>
<td>Interconnection charge (2)</td>
<td>86.2 (DTS) 98.0 (DTS)</td>
<td>(1.8) (DTS)</td>
<td>6.0 (DTS)</td>
<td>(5.8) (DTS)</td>
<td></td>
</tr>
<tr>
<td>Other system support services charge (3)</td>
<td>1.4 (DTS) 0.7 (DTS)</td>
<td>0.7 (DTS)</td>
<td>(0.4) (DTS)</td>
<td>0.3 (DTS)</td>
<td></td>
</tr>
<tr>
<td>Voltage Control (4)</td>
<td>8.4 (DTS) 3.8 (DTS)</td>
<td>4.6 (DTS)</td>
<td>(2.0) (DTS)</td>
<td>2.6 (DTS)</td>
<td></td>
</tr>
<tr>
<td>YTD February 2009 Deferral Amount (5)</td>
<td>119.0 (DTS) 129.7 (DTS)</td>
<td>(10.7) (DTS)</td>
<td>19.8 (DTS)</td>
<td>9.1 (DTS)</td>
<td></td>
</tr>
</tbody>
</table>

| **March 2009 Estimate**       |                    |              |                            |                                                   |                                                |
| Operating reserve charge (1) | 6.4 (DTS) 4.0 (DTS) | 2.3 (DTS)     | 8.4 (DTS)                 | 10.8 (DTS)                                       |                                                |
| Interconnection charge (2)   | 48.9 (DTS) 49.1 (DTS) | (0.3) (DTS) | 3.1 (DTS)                  | 2.8 (DTS)                                        |                                                |
| Other system support services charge (3) | 0.7 (DTS) 0.6 (DTS) | 0.2 (DTS)     | (0.2) (DTS)             | (0.0) (DTS)                                      |                                                |
| Voltage Control (4)          | 4.4 (DTS) 3.2 (DTS) | 1.2 (DTS)     | (1.0) (DTS)             | 0.1 (DTS)                                        |                                                |
| Estimated March 2009 Deferral Balance | 60.3 (DTS) 56.9 (DTS) | 3.4 (DTS)     | 10.3 (DTS)              | 13.7 (DTS)                                       |                                                |

| **Q2 2009 Estimate**       |                    |              |                            |                                                   |                                                |
| Operating reserve charge (1) | 25.3 (DTS) 57.8 (DTS) | (32.5) (DTS) | -                         | (32.5) (DTS)                                     |                                                |
| Interconnection charge (2)   | 145.1 (DTS) 147.9 (DTS) | (2.8) (DTS) | -                         | (2.8) (DTS)                                      |                                                |
| Other system support services charge (3) | 2.1 (DTS) 1.7 (DTS) | 0.5 (DTS)     | -                         | 0.5 (DTS)                                        |                                                |
| Voltage Control (4)          | 12.1 (DTS) 9.6 (DTS) | 2.6 (DTS)     | -                         | 2.6 (DTS)                                        |                                                |
| Estimated Q2 2009 Deferral Ending Balance | 184.7 (DTS) 217.0 (DTS) | (32.3) (DTS) | -                         | (32.3) (DTS)                                     |                                                |

| **Total Estimated YTD Deferral Balance at Q2 2009** |                    |              |                            |                                                   |                                                |
| Operating reserve charge (1) | 54.7 (DTS) 89.1 (DTS) | (34.4) (DTS) | 24.6 (DTS)              | (9.8) (DTS)                                       |                                                |
| Interconnection charge (2)   | 280.2 (DTS) 295.0 (DTS) | (14.8) (DTS) | 9.1 (DTS)                  | (5.7) (DTS)                                       |                                                |
| Other system support services charge (3) | 4.3 (DTS) 2.9 (DTS) | 1.4 (DTS)     | (0.6) (DTS)             | 0.8 (DTS)                                        |                                                |
| Voltage Control (4)          | 24.9 (DTS) 16.6 (DTS) | 8.3 (DTS)     | (3.0) (DTS)             | 5.3 (DTS)                                        |                                                |
| Estimated Deferral Balance at Q2 2009 | 364.1 (DTS) 403.6 (DTS) | (39.6) (DTS) | 30.1 (DTS)              | (9.5) (DTS)                                       |                                                |

Numbers may not add due to rounding.
1. Operating Reserve charges
   - Effective January 1, 2006 Operating reserve charges are allocated 100% to DTS customers. The costs include Operating Reserves, Generator Remedial Action Schemes, and Black Start.
2. Interconnection charges
   - Effective January 1, 2006 Interconnection charges are allocated 100% to DTS customers. Interconnection charges include Wires, ILRAS, Other Industry and G & A. Revenues collected from rate schedules other than DTS have been included in revenues collected from Interconnection charges.
3. Other System Support Services charges are allocated 100% to DTS customers.
4. Effective January 1, 2006 Voltage Control (Transmission Must Run) costs are allocated 100% to DTS customers.
5. Q2 2009 forecasted Rider C collections (refunds) have not been incorporated this table.

**DTS Customers**: In Q2 2009, a Rider C net adjustment of $0.72 per MWh will be added to the DTS rates as a charge. [\(\frac{-9.5\ million}{13,054\ GWh} = 0.72\ per\ MWh\)]

<table>
<thead>
<tr>
<th>Rider C Rates for Q2 2009</th>
<th>$/MWh DTS</th>
<th>DTS Q2/09 GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Reserve</td>
<td>$0.75</td>
<td>13,054</td>
</tr>
<tr>
<td>Interconnection Charge</td>
<td>$0.44</td>
<td></td>
</tr>
<tr>
<td>Other System Support Services Charge</td>
<td>(0.06)</td>
<td></td>
</tr>
<tr>
<td>Voltage Control</td>
<td>(0.41)</td>
<td></td>
</tr>
<tr>
<td><strong>Total charge (refund)</strong></td>
<td>$0.72</td>
<td></td>
</tr>
</tbody>
</table>

The analysis of the forecasted deferral account balances are the AESO’s best estimate of the costs and revenues based on the information available at the time that this summary was prepared. This information is an estimate only and may not represent the actual costs incurred and revenue collected.

Note - All references to DTS customers or rate schedules include FDS.
Discussion and Questions on 2008 Deferral Account Reconciliation

• Concerns with proposed approach
• Support for immediate interim settlement
• Need for formal comment process
  – In mid-March
• Need for technical meeting
  – In April or May
• Alternatives to written proceeding
  – Potential for negotiated settlement

Additional Discussion on Future Deferral Account Matters
Information on Future Rate Applications

- AESO preparing to file 2009 rates update information
  - Updated rates expected to be effective mid-2009
- Average rate increase expected to be about 18%
  - Goal is to reduce deferral account amounts dealt with through Rider C
- AESO proposing change to DTS operating reserve charge in 2010 tariff application
  - Planned to be filed in Q3 2009, with rates effective in Q3 2010
- Proposed operating reserve charge will better match costs on monthly basis and reduce deferral account balances
- Changes may allow consideration of prospective Rider C

Review of Rider C Practices

- Change to practices generally do not require tariff approval
- Seeking stakeholder comments
- Consideration of deferral account balance thresholds above which practice may be revised
### Exclusion of Year-End Balances From Q1 Rider C

- Prior to 2009, all Q1 Rider C amounts were calculated to recover prior year-end balance and Q1 forecast amount.
- For 2009 Q1 Rider C, AESO calculated it to include Q1 forecast amount only.

<table>
<thead>
<tr>
<th>Include Year-End Balance</th>
<th>Exclude Year-End Balance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cannot begin reconciliation until after Q1 ends (May)</td>
<td>Can begin reconciliation after year-end (February)</td>
</tr>
<tr>
<td>Year-end balance recovered earlier (Feb-Apr)</td>
<td>Year-end balance recovered later (May with interim settlement or late in year with final settlement)</td>
</tr>
<tr>
<td>Rider C recovery subject to change in reconciliation</td>
<td>Recovery through reconciliation comparatively final</td>
</tr>
</tbody>
</table>

### Exclusion of Prior-Year Balances From Quarterly Rider C

- Since 2004, Rider C amounts have been calculated to recover current year balances only (except Q1 which includes prior Q4 year-end balances).
- Prior-year amounts (except for Q4’s inclusion in Q1 Rider C) are recovered through deferral account reconciliations.

<table>
<thead>
<tr>
<th>Include Prior-Year Amounts</th>
<th>Exclude Prior-Year Amounts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Misalignment between customers and variances</td>
<td>Full alignment of customers and variances by production month</td>
</tr>
<tr>
<td>Prior-year amounts recovered earlier (in year of transaction)</td>
<td>Prior-year amounts recovered later (in year following transaction)</td>
</tr>
<tr>
<td>Rider C recovery subject to change in reconciliation</td>
<td>Recovery through reconciliation comparatively final</td>
</tr>
</tbody>
</table>
Alternatives to Full Reconciliations

- When can full reconciliations of deferral account balances be stopped?
  - Under full reconciliation, variances allocated to customers on most current customer revenue
- Currently application includes full reconciliations for six years (2003 to 2008)
  - Only two most recent years have deferral account balances greater than ±$0.1 million (excluding removal of interest redistribution)
  - Total adjustments for 2003 through 2006 only $0.26 million (excluding removal of interest redistribution)
- Consideration of materiality thresholds below which full reconciliation would not be completed

1. “Frozen Allocators” Alternative

1. Create annual allocators based on second or third reconciliation or on most recent approval after some threshold is reached
   - All subsequent adjustments allocated by annual frozen allocators
   - Similar to approach for 2002, which has been “frozen” since 2003 deferral account reconciliation
   - Monthly frozen allocators not materially simpler than full reconciliation
2. “Permanent Termination” Alternative

2. Permanently discontinue both full reconciliations and reconciliations of adjustments after second or third reconciliation or after some threshold is reached
   - All subsequent adjustments “rolled up” into “oldest” reconciliation that is not yet terminated
   - Don’t reopen closed-year reconciliations

3. “Indefinite Termination” Alternative

3. Temporarily terminate full reconciliations and reconciliations of adjustments after second or third reconciliation or after some threshold is reached, but re-open for material adjustments above some threshold
   - For immaterial adjustments, “roll up” adjustments into “oldest” reconciliation that is not yet terminated
   - For material adjustments, reverse “rolled-up” adjustments and re-reconcile year in which material adjustment occurred
   - Reversal of “rolled-up” adjustments may prevent roll-up of year which would otherwise have happened
   - How should “rolled-up” adjustments be allocated to customers in destination year?
### Indefinite Termination Example

<table>
<thead>
<tr>
<th>Production Year</th>
<th>2009 Deferral Account Reconciliation Application</th>
<th>2010 Deferral Account Reconciliation Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>Full reconciliation</td>
<td>No Material Adjustments Prior to 2008 Production Year</td>
</tr>
<tr>
<td>2009</td>
<td>Full reconciliation</td>
<td>Material Adjustment in 2004 Production Year</td>
</tr>
<tr>
<td>2008</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2007</td>
<td>Full reconciliation</td>
<td>Full reconciliation</td>
</tr>
<tr>
<td>2006</td>
<td>Full reconciliation</td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2005</td>
<td>Roll into 2007</td>
<td>Roll into 2008</td>
</tr>
<tr>
<td>2004</td>
<td></td>
<td>Roll into 2007</td>
</tr>
<tr>
<td>2003</td>
<td></td>
<td>Roll into 2004</td>
</tr>
<tr>
<td>2002</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2001</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Materiality Thresholds

- **Minimum of three full reconciliations**
  - Still necessary?
- **Cost adjustment not considered material if less than ±1% of AESO revenue requirement**
  - About ±$10 million for 2009
- **Revenue adjustment not considered material if individual customer impact of deferral account reconciliation is less than ±$50,000**
Deferral Account Rider C Changes

- Rider C changes would require tariff approval
- Rider C purpose is “to restore the deferral account balances to zero over the following calendar quarter”
- Requires forecasting of the upcoming quarter
  - For example, must forecast Q1 variance to determine Q1 Rider C
- Alternatively, could use only actual variances
  - May decrease Rider C variability
  - May cause AESO to hold surpluses and finance shortfalls longer
- Alternatively, could address variances over remaining months in calendar year, as opposed to next quarter
  - Similar to Rider E approach

Deferral Account Rider B Changes

- Rider B changes would require tariff approval
- Rider B purpose is to recover unexpected deficiencies or refund unexpected surpluses of working capital
- Currently available only as a “percentage increase or decrease…applied to charges under the rate schedules…in the current Billing Period”
- Revise to allow for more specific implementation
  - By rate component
  - By MWh (like Rider C)
- Potentially possible to modify Rider C to accommodate Rider B purpose
Next Steps

• Further consultation on rider practices and rider changes?
  – As part of 2010 GTA consultation being held from February to June

• Try to propose as part of 2010 tariff application
  – Planned to be filed in Q3 of 2009
  – New tariff expected to be effective Q3 of 2010

• Further assessment of Prospective Rider C

• Discussion paper and comment process?

Discussion and Questions on Future Deferral Account Matters
For More Information

- John Martin
  Director, Tariff Applications
  Phone (403) 539-2465
  E-mail john.martin@aeso.ca

- Carol Moline
  Director, Accounting & Treasury
  Phone (403) 539-2504
  E-mail carol.moline@aeso.ca

- Application on AESO web site at www.aeso.ca
  Tariff ▶ Current Applications ▶ 2008 Deferral Account
  Reconciliation
October 22, 2009

Tariff Changes Related to TOAD Working Group Members
AESO Stakeholders

Dear Stakeholder:

Re: Incorporation of Confidential Information and Dispute Resolution ISO Rules Into the AESO Tariff

As discussed at the general stakeholder tariff consultation meeting on June 24, 2009, the AESO has investigated consolidating confidential information and dispute resolution provisions into a single location in the AESO’s authoritative documents. The AESO invites stakeholders to comment on the following proposal to locate those provisions in the ISO rules and incorporate them by reference in the AESO tariff.

The AESO recently proposed changes to ISO Rule 10 on information exchange and ISO Rule 11 on dispute resolution. The changes rename, reorganize, and rewrite the content of those rules to improve the clarity and consistency of the language, eliminate duplication or unnecessary content, and consolidate subject matter where the information is dispersed across several documents: The changes also convert these rules to a standard format as part of the AESO’s Transition of Authoritative Documents (TOAD) process.

Having considered the draft changes, the AESO now proposes that the revised rules be incorporated by reference to address confidential information and dispute resolution in the AESO tariff. The AESO considers that uniform provisions for all authoritative documents, for each of confidential information and dispute resolution, provide clear, transparent, and consistent provisions for these matters.

To allow tariff stakeholders an opportunity to review the proposed ISO rule changes in the context of the proposed tariff changes, the AESO has extended the ISO rules comment period to November 9, 2009. The AESO is also posting notice of the proposed changes on the 2010 tariff consultation page of its website, in addition to the usual posting on the proposed ISO rules and OPP changes page.

The AESO has attached to this letter draft terms and conditions that incorporate the proposed rules by reference. Interested parties are invited to provide comments on the proposed tariff provisions using the comment form available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff, in the section for the Tariff Changes Related to Transition of Authoritative Documents (TOAD) Working Group. Please return the completed comment form to Ghaz Marinho at ghaz.marinho@aeso.ca, by Monday, November 9, 2009.
The original letter of notice on the proposed rule changes is also available on the AESO website at www.aeso.ca by following the path Rules & Standards ► ISO Rules ► Proposed ISO Rules & OPP Changes, as the document titled “Letter of Notice - Proposed Level II Changes to Existing ISO Rule 10 Information Exchange and ISO Rule 11 Dispute Resolution” (posted: October 8, 2009). Interested parties are invited to provide comments on the proposed rule changes, also to Ghaz Marinho at ghaz.marinho@aeso.ca, using the comment matrix linked in the letter of notice.

This letter and all other printed information related to the Tariff Changes Related to TOAD Working Group and the 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Evelyn Kelly at 403-539-2468 or evelyn.kelly@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Evelyn Kelly, TOAD Project Manager, Consultant to AESO
SECTION 16
CONFIDENTIAL INFORMATION

Confidential Information

1(1) Both the ISO and customers will treat information as confidential in accordance with the provisions of section 103.1 of the ISO rules regarding confidential information. Confidential information will be disclosed only in accordance with the provisions of that ISO rule.

(2) When exchanging information related to the ISO tariff, a customer shall be considered a market participant for the purpose of the confidential information provisions established under section 103.1 of the ISO rules.

System Access Service Request Information

2 Information related to a specific system access service request will not be treated as confidential if it is disclosed in order to comply with participant involvement program requirements prior to submission of a facilities application to the Commission.

Revision History

2009-10-22 Revised to refer to provisions of ISO rules. Draft released for stakeholder comment.
Dispute Resolution Process

1(1) A dispute between a customer and the ISO related to the ISO tariff will be addressed in accordance with the provisions of section 103.2 of the ISO rules regarding dispute resolution.

(2) When addressing a dispute related to the ISO tariff, a customer shall be considered a market participant for the purpose of the dispute resolution provisions established under section 103.2 of the ISO rules.

Continued Obligation

2 Pending resolution of any dispute, the ISO and the customer will continue to perform their respective obligations under the ISO tariff.

Revision History

2009-10-22 Revised to refer to provisions of ISO rules. Draft released for stakeholder comment.
The AESO invites stakeholders to provide comments on draft terms and conditions that incorporate, by reference, proposed ISO rules on confidential information and dispute resolution. The AESO considers that uniform provisions for all authoritative documents, for each of confidential information and dispute resolution, provide clear, transparent, and consistent provisions for these matters. The AESO acknowledges that stakeholder comments are provided without prejudice to the rights of customers under the AESO tariff, the Electric Utilities Act, regulations, and decisions of the Alberta Utilities Commission.

Request for Comments: October 22, 2009
Consultation Period: October 22, 2009 through November 9, 2009

Comments From:
Date:
Contact:
Phone:
E-mail:

<table>
<thead>
<tr>
<th></th>
<th>Confidential Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>1(1)</td>
<td>Both the ISO and customers will treat information as confidential in accordance with the provisions of section 103.1 of the ISO rules regarding confidential information. Confidential information will be disclosed only in accordance with the provisions of that ISO rule.</td>
</tr>
</tbody>
</table>

Reasons for Stakeholder Position:

<table>
<thead>
<tr>
<th></th>
<th>(2) When exchanging information related to the ISO tariff, a customer shall be considered a market participant for the purpose of the confidential information provisions established under section 103.1 of the ISO rules.</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

|   | 2 Information related to a specific system access service request will not be treated as confidential if it is disclosed in order to comply with participant involvement program requirements prior to submission of a facilities application to the Commission. |

Reasons for Stakeholder Position:
17 Dispute Resolution

1(1) A dispute between a **customer** and the **ISO** related to the ISO **tariff** will be addressed in accordance with the provisions of section 103.2 of the **ISO rules** regarding dispute resolution.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

(2) When addressing a dispute related to the ISO **tariff**, a **customer** shall be considered a **market participant** for the purpose of the dispute resolution provisions established under section 103.2 of the **ISO rules**.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

2 Pending resolution of any **dispute**, the **ISO** and the **customer** will continue to perform their respective obligations under the ISO **tariff**.

<table>
<thead>
<tr>
<th>Support</th>
<th>Oppose</th>
<th>Indifferent</th>
</tr>
</thead>
</table>

Reasons for Stakeholder Position:

**Addendum Comments**

Please return this form with your comments by November 9, 2009, to:

Ghaz Marinho  
Regulatory Services  
E-mail: ghaz.marinho@aeso.ca  
Phone: 403-539-2474  
Fax: 403-539-2949
June 8, 2009

Tariff Changes Related to TOAD Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Tariff Changes Related to TOAD Working Group

The first meeting of the Tariff Changes Related to TOAD Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- Time: 11:00 AM to 1:00 PM
- Date: Tuesday, June 9, 2009
- Location: Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- Refreshments: Light working lunch and beverages

This working group includes the following members:

- AltaLink: Cayla Saby
- ATCO Power: Kim Johnston
- ENMAX: Penny Haldane
- EPCOR: Lynn Meyer
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin
- Consultant to AESO: Evelyn Kelly

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions** 11:00 AM
   - Please indicate which stakeholders you represent

2. **Review agenda** 11:10 AM

3. **Review draft working groups terms of reference** 11:15 AM
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
– Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
– A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for Tariff Changes Related to TOAD 11:20 AM
- Please review the enclosed background on the Transition of Authoritative Documents (TOAD) initiative before the meeting, if possible:
- Is there other background that participants consider particularly relevant?

5 Scope for Tariff Changes Related to TOAD Working Group 11:30 AM
- Movement of tariff definitions to centralized glossary
- Removal of technical requirements from tariff where they appropriately exist elsewhere (in standards, for example)
- Consolidation of information currently appearing in multiple documents (DOS requirements, for example)
- Standardization and consolidation of common requirements (confidentiality, for example)
- Working group will not review or discuss the following items which are being addressed through the TOAD workgroup and project:
  – framework for organization and location of documents;
  – administration of authoritative documents;
  – standardization of terms and definitions among authoritative documents; and
  – standard template for authoritative documents.

6 Movement of tariff definitions to centralized glossary 11:45 AM
- Centralized glossary concept as separate authoritative document
- Management of approvals of definitions and incorporation by reference
- What information would be required for tariff application?

7 Removal of technical requirements from tariff 12:15 PM
- Remove Article 4.4 on PSS and AVR requirements for generators
- Remove Article 7 paragraphs on metering testing, data, and signals
- Remove Article 8.2 on forecast information
- Remove Appendix A on metering equipment information

8 Follow-up required for next meeting 12:45 PM
- Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s) 12:55 PM

10 Adjourn 1:00 PM
This agenda and all other printed information related to the Tariff Changes Related to TOAD Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders' participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Evelyn Kelly at 403-539-2468 or evelyn.kelly@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Evelyn Kelly, TOAD Project Manager, Consultant to AESO
AIDS 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   • Substations included in POD cost data set
   • Inflation index to escalate POD cost data to 2010
   • Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   • Respond to AUC directions on analysis of TFO O&M costs
   • Determine if TFO O&M costs are energy-related
   • Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   • Methodology to analyze and assess design of operating reserve charge
   • Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   • Rate design principles for Fort Nelson and similar services
   • Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   • Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   • Rate design principles for higher-priority export and import services
   • Similarities and differences between domestic and intertie services
   • Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   • Rate design principles for deferral account riders
   • Practicality of improving allocation accuracy of deferral account riders
   • Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

### 3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

### 4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

### 5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
BACKGROUND ON THE TRANSITION OF AUTHORITATIVE DOCUMENT INITIATIVE

The AESO initiated the Transition of Authoritative Document project (TOAD) to address concerns with regard to the AESO’s authoritative documents (documents):

- The mandatory rights, requirements and obligations are not always clear within documents, for both market participants and AESO,
- The mandatory requirements and obligations are written with other non-mandatory content and it can be difficult to discern the rights, requirements and obligations,
- The documents are written in several different formats which makes it more difficult to find information,
- It is not always clear who the rights, requirements and obligations apply to,
- It is difficult to find documents on the AESO website,
- There is inconsistent consultation with regard to documents.

TOAD objectives include:

- Create a standard template for authoritative documents,
- Standardize terms and definitions among the authoritative documents,
- Elimination of overlaps, duplication and gaps among documents,
- Create a framework for organization and location of documents,
- Create an approach(es) for administering authoritative documents,
- Transition the documents into the standard structure(s) and framework using the defined approach.

Two stakeholder sessions were held on TOAD, September 2008 and February 2009. At the February 2009 session stakeholders expressed an interest in forming a TOAD workgroup for the sake of providing more focused input on the definitions, template, framework and transition approach and priorities. The AESO subsequently formed a TOAD workgroup and between April and June obtained further input on the definitions, template and framework.

AUTHORITATIVE DOCUMENTS

For background, the AESO has determined that Authoritative Documents are:

- Legal document created under legislative authority,
- Binding and mandatory AESO and market participant obligations,
- Material impact on AESO and market participant rights,
- May (likely will) have to be filed with the Alberta Utilities Commission.

Essentially authoritative documents include the AESO rules (inclusive of the Operating Policies and Procedures), tariff and reliability standards.

EVOLVING RECOMMENDATIONS FROM THE TOAD WORKGROUP AND THE TARIFF

The TOAD workgroup is in the final stages of preparing a set of recommendations for the AESO’s consideration. Given the timing of the Tariff application process there are changes that could be initiated in the tariff application process thereby leveraging and
benefiting from some of the recommendations; these areas are set out below and will be discussed in more detail in the TOAD-Tariff workgroup.

**STANDARDIZED TERMS AND DEFINITIONS**

The TOAD workgroup is advocating that the AESO create a centralized glossary for authoritative documents rather than keeping separate glossaries or maintaining definitions within documents. The concept is that a term and definition, where appropriate, would be used consistently among documents. Key benefits of a centralized glossary include:

- Ease of use (one stop shopping)
- Elimination of duplication and conflicts

The concept is illustrated below.

![Diagram of ISO Authoritative Documents, Glossary, ISO Rules, ISO Tariff, Alberta Reliability Standards]

**STANDARD TEMPLATE**

The TOAD workgroup determined that the key elements of the template should include:

- Legislative Authority
  - References the legislation that provides the authority to create the document.

- Applicability
  - States who the document is applicable to; as specific as possible,
  - States any applicability conditions.

- Requirements
  - States the requirements for the market participant and the AESO.
  - The section will allow for permissive language; more specifically the use of the word ‘may’ either for a market participant or the AESO where appropriate.

- Appendices
  - Processes and procedures where they support the requirements.

- Revision History

**FRAMEWORK AND ELIMINATION OF OVERLAPS**

Currently there are related subject areas where rights, requirements and obligations are set out in the AESO rules, tariff, reliability standards and other documents on the AESO website. To the extent possible there is a desire to consolidate related subject matter in one area.
Background - AESO Credit Risk

• Credit Risk is that a debtor is not able to honour its obligations resulting in a default by the debtor.
  – In the Real Time Energy Market, credit risk is the risk that a net load participant will fail to pay for energy received (receivable risk).
  – Under the Transmission Tariff, credit risk is the risk that a customer will fail to pay for services it has received (receivable risk).

• The AESO manages credit risk for its participants/customers in accordance with the ISO rules and the Transmission Tariff.
  – The AESO is not subject to credit losses as a result of any defaults as losses flow through to participants/customers.
The AESO’s Credit Exposures

- A customer’s operating requirement is a participant’s cumulative obligations owing to the AESO
  Operating Requirement is the aggregate of the following components:
  - Energy Market Transaction Costs (net load purchases from the AESO)
  - Transmission Services Costs (DTS or STS charges plus any security required for CCAs)
  - Other items
- A customer’s security requirements are calculated as follows:
  - Operating Requirements
    - Less:
      - Unsecured Credit Allocated to Customer
    - Equals:
      - Required Customer Security

AESO Credit Policy – Transmission Tariff and Energy Market Rules

The AESO Tariff:
- Article 6.2: Security for new Transmission Facilities and related Article 9.2 Payment of Contributions
  - Security as determine by the AESO, not to exceed estimated construction costs (covers cancellation costs)
- Article 15.1 Credit Requirements (Financial Security, Billing and payment terms)
  - Customer must comply with the AESO’s security requirements - up to 3 three months payments (covers receivables)

ISO rules:
- ISO Rule 2.1, Appendix 3 – Prudential Requirements (market participants)
### Credit Policy - Unsecured Credit Limits for Rated Companies

- Organization (or Guarantor) are required to have a long-term unsecured debt rating provided by an AESO Recognized Ratings Agency (DBRS, Moody’s, S&P).
- Unsecured credit is granted to Organization’s based on their credit rating (or S&P equivalent) as follows:

<table>
<thead>
<tr>
<th>Rating</th>
<th>Unsecured Credit Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>AAA</td>
<td>$ 25,000,000</td>
</tr>
<tr>
<td>AA</td>
<td>20,000,000</td>
</tr>
<tr>
<td>A</td>
<td>15,000,000</td>
</tr>
<tr>
<td>BBB</td>
<td>10,000,000</td>
</tr>
<tr>
<td>&lt;BBB</td>
<td>0</td>
</tr>
</tbody>
</table>

### Credit Policy - Unsecured Credit Limits for Non-Rated Companies

- The AESO may grant up to the following Unsecured Credit Limits to a Non-Rated organization (or Guarantor) based on the following Credit Ratings scale:

<table>
<thead>
<tr>
<th>Proxy Credit Rating</th>
<th>Unsecured Credit Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>AAA</td>
<td>$ 10,000,000</td>
</tr>
<tr>
<td>AA</td>
<td>5,000,000</td>
</tr>
<tr>
<td>A</td>
<td>2,500,000</td>
</tr>
<tr>
<td>BBB</td>
<td>1,250,000</td>
</tr>
<tr>
<td>&lt;BBB</td>
<td>0</td>
</tr>
</tbody>
</table>

- The amount of the Unsecured Credit Limit provided to a Non-Rated Organization (or Guarantor) cannot exceed 0.5% of the Organization’s Tangible Net Worth (“TNW”).
Credit Policy - Unsecured Credit Limits for Non-Rated Companies Con’t

• A Non-Rated Organization (or a Guarantor) may apply for an Unsecured Credit Limit based on a Proxy Credit Rating to be determined by the AESO.

• Requirements from the non-rated organization include:
  – Annual Audited Financial Statements, and
  – Quarterly Financial Statements

Credit Policy - Types of Security Accepted by the AESO

• Letter of Credit
• Cash Collateral
• Guarantee
• Asset Securitization
3 COMMON TRANSMISSION AND DISTRIBUTION ISSUES

3.1 2009 Plant and Other Assets Opening Balances

25. During the course of the oral hearing, AE indicated its intention to update the opening balances for plant and other assets for 2009 to reflect the 2008 actual closing balances:

Q. During the break, there was -- just to point out one further question in relation to the capital, and now that you have the actual opening and closing balances for 2008, is it ATCO's intention to reflect the closing balances for 2008 in the opening balances for 2009 at the time of the refiling?
A. That's correct.15

Commission Findings

26. Both the Consumer Group (CG) and the UCA recommended that AE’s 2008 actuals be adopted as the starting point for AE’s 2009 test year. There appears to be agreement among parties that the 2008 actual closing balances should be reflected in the 2009 opening balances. The Commission considers this to be a prudent course of action and directs AE in its compliance filing to update its 2009 opening balances to reflect the 2008 actual closing balances for plant and other assets, except for the amounts related to the Additional Deductions.16 AE is directed to identify the Additional Deductions separately and to treat these amounts as placeholders for the compliance filing.

3.2 Management Fee

27. In its Application, AE noted that the current regulatory treatment of existing and forecast levels of contributions in aid of construction (CIAC) prevents AE from earning a fair and reasonable return on assets that are used and useful in the provision of service to customers. Specifically, AE submitted that it retains the full responsibility to own, operate and maintain assets financed by CIAC but does not receive any compensation for the performance of these functions.17 AE engaged an expert witness, Dr. Charles Cicchetti of Pacific Economics Group, to assist in developing its position on these matters. AE proposed the following management fees and corresponding “notional equity percentages” for 2009 and 2010:18

15 Transcript Volume 4, page 493, starting at line 22
16 Additional Deductions refers to income tax deductions for easements costs, stock handling costs, and removal and abandonment costs. For further information refer to Section 6.2 of this Decision
17 AE Application, Section 31, Attachment 1, page 3
18 AE Updates Rebuttal, Schedule 1, page 1 and 2, and AE Rebuttal Evidence, page 248
Table 4. Summary of AE Management Fee Amounts and Notional Equity Percentage

| Test Year ($ Million) |  
|----------------------|----------------------|
| 2009 | 2010 |
| **Transmission Management Fee** |  
| Percent for Amortized Payment | 6.83% | 6.83% |
| Amortized Payment Amount | 2.3 | 3.1 |
| **Distribution Management Fee** |  
| Percent for Amortized Payment | 6.46% | 6.46% |
| Amortized Payment Amount | 8.5 | 10.0 |
| **Total Transmission and Distribution Management Fee** | 10.8 | 13.1 |

28. CG engaged an expert witness, Mr. William Marcus of JBS Energy, to evaluate AE’s proposal to collect management fees. The UCA, CG, Industrial Power Consumers Association of Alberta (IPCAA), TransCanada Keystone Pipeline GP Ltd. (Keystone) and First Nations did not support AE’s proposal to collect the management fee and argued that the management fee:

- was contrary to the EUA;
- should be dealt with in the next AESO GTA;
- contributed to rate shock and added unnecessary costs to customers;
- was excessive;
- would compensate for risks twice;
- defeated the purpose of CIAC;
- violated the concept of prospective regulation; and
- should be replaced with Keystone’s AESO Rider I proposal.

29. AE maintained that a management fee was necessary because:

- AE does not receive any compensation for the ownership, operation and maintenance of the assets financed by CIAC and the assumption of risks associated with these assets;
- section 122(1)(h) of the EUA clearly provides the Commission the authority to grant the requested relief; and
- the level of CIAC diminishes its approved level of return (currently 8.75 percent) by some 57 basis points to an effective return of 8.18 percent.

30. AE submitted that it should be treated as having separate Transmission and Distribution entities and argued that its management fee proposal with respect to CIAC had been fully justified and that it should be approved for inclusion in revenue requirement for the test years.

Commission Findings

31. The Commission notes that the Chair in this proceeding questioned Dr. Cicchetti with respect to the services that would be provided in return for the management fee. In reviewing the response of Dr. Cicchetti, the Commission considers that it is unclear what services were to be provided. In addition, AE submitted that its request for a management fee was grounded in the fact that it retains the full responsibility to own, operate and maintain assets financed by

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19 Transcript Volume 5, page 679, line 12 to page 680, line 5
CIAC but does not receive any compensation for the performance of these functions. However, the Commission notes the evidence of Mr. Marcus:

> What is actually being “managed” for contributed property is O&M expense. These expenses and the cost of managing these expenses are included in rates, and the increase in contributions has not resulted in a significant increase in ATCO’s business risk.\(^{20}\)

32. As noted by Mr. Marcus the costs of managing the contributions are included in rates today.\(^{21}\) Dr. Cicchetti also acknowledged that there was no cost basis for the management fee.\(^{22}\)

33. Prior to approving any new fees, charges, or costs such as a management fee, the Commission must be satisfied that the charge is just and reasonable. AE has not convinced the Commission that the management fee is just and reasonable. The evidence is not clear or compelling as to what specific services are being rendered in return for the management fee, for which compensation is not presently provided.

34. The Commission has also considered the arguments in relation to what percentage level of CIAC causes a problem for a utility. The Commission notes that while Mr. Marcus contended that CIAC was not a problem, he acknowledged during the hearing that:

> If 100 percent of a utility's assets were financed by contributions, you would probably need to look at some other mechanism for providing a fair return, such as, for example, a return margin.\(^{23}\)

and

> I think my answer is pretty much the same as 75. You'd have to look at it, but when you start getting numbers closer to 50 percent, you start getting returns that are a viable business, and you may start thinking about some other issues to make sure that you've got a viable business there….

> But as the number comes down, you can start looking at the business as a whole. You know, whereas if the number is 100 percent or 75, you've probably got to make sure that you provide a viable business.\(^{24}\)

35. Thus to Mr. Marcus, it appears that CIAC could become a problem if it reaches a level somewhere between 50 percent and 100 percent of the total investment in utility property. In contrast, Dr. Cicchetti considered that at the 10 percent level, CIAC was a problem,\(^ {25}\) and at this level, return on equity is probably off by somewhere between 50 and 75 basis points.\(^ {26}\) The Commission notes that there is a wide variance between the percentage levels and no definitive point at which the experts concluded that CIAC needs to be addressed. In view of the variance in the experts’ opinions it is not clear to the Commission that the current level of CIAC justifies the implementation of a management fee.

\(^{20}\) CG Evidence of Mr. Wm. Marcus, page 3  
\(^{21}\) CG Evidence of Mr. Wm. Marcus, page 10  
\(^{22}\) Transcript Volume 5, page 681, lines 3-4  
\(^{23}\) Transcript Volume 6, page 871, lines 21-24  
\(^{24}\) Transcript Volume 5, page 626, lines 8-15  
\(^{25}\) UCA-AE-81(a)  
\(^{26}\) Transcript Volume 6, page 873, lines 3-12
36. For the above reasons, the Commission considers that it should not approve the management fee. Accordingly, the Commission denies AE’s requested management fee for the current test years.

37. Following the close of the evidentiary portion of this proceeding, a panel of the Commission heard AltaLink Management Ltd.’s (AltaLink) 2009-2010 General Tariff Application (Proceeding 102). In Proceeding 102 the concept of a management fee was raised and discussed as was Keystone’s Rider I proposal addressing this concept. Following the close of evidence in Proceeding 102, the impact of Rider I on the business risk of a utility was also examined in the 2009 Generic Cost of Capital proceeding. Given that the management fee concept has been raised in both this proceeding and Proceeding 102, and the Rider I proposal has been raised in all three proceedings, the Commission is concerned that an approach for dealing with this concept on a global basis has not been available. The Commission considers that compensation for the ownership, operation and maintenance of assets financed by CIAC should be addressed comprehensively, rather than in individual utilities’ tariff applications, or in the Generic Cost of Capital proceeding.

38. The Commission finds that consideration and evaluation of CIAC and related compensation to the utility could be more efficiently and effectively addressed going forward at a generic proceeding, which would allow for a more detailed review of all relevant issues at one time and by all potentially affected parties. The Commission will advise all parties in the near future as to the process that will be established.

3.3 Inflation

39. In the Application, AE proposed different inflation rates for the following categories: Labour, Other and Contractors. The inflation rates for each of these categories are summarized below. For ease of reference, the corresponding recommendations made by each of CG and the UCA are also shown.

Table 5. Summary of Inflation Recommendations

| Category          | AE Original | AE Revised | CG           | UCA
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Labour</td>
<td>6.0</td>
<td>6.9</td>
<td>6.0</td>
<td>6.9</td>
</tr>
<tr>
<td>Other</td>
<td>5</td>
<td>5</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Contractor and Capital</td>
<td>10</td>
<td>10</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>

40. The following table sets out the Commission’s findings for each of the inflation categories. The positions of the parties and the Commission’s findings for each of these inflation categories are in the subsections that follow.

27 2009 Generic Cost of Capital proceeding EPS ID 85 – Transcript Volume 11, starting at page 1858
28 UCA Argument, page 11
29 The Commission’s summary of CG’s recommendation is based on the following “…the wage increases for 2009 and 2010 should be established at 3.5% for 2009 …with one exception. Since the agreement with CEWA is already in place for 2009, the wage increases (5.25% plus 0.5% step increases) resulting from that agreement should be allowed for 2009.”
Amortized Customer Contribution Option and
Other Contribution Provisions Working Group
TransCanada Rider I Proposal

At the Customer Contributions Working Group meeting on June 10, 2009, the AESO committed
to compile and distribute the Information filed by TransCanada Energy in AltaLink’s 2009-2010
Transmission Facility Owner Tariff Application proceeding, relating to TransCanada’s proposal
for an amortized customer contribution Rider I.

That information is attached, and includes the following:

(a) TransCanada Energy evidence, filed on March 6, 2009;

(b) TransCanada Energy responses to ASBG/PGA information requests (excluding
ASBG/PGA-TCE 7 which simply provided a copy of Article 9 of the AESO’s terms and
conditions), filed on March 27, 2009;

(c) TransCanada Energy oral evidence of Vince Kostesky and Dan Levson from pages
1499-1593 of Volume 9 of the hearing transcripts, dated April 30, 2009;

(d) TransCanada Energy response to undertaking at transcript page 1576 to provide the
three scenarios discussed at pages 1553 and 1554, filed as Exhibit 271 on May 6, 2009;

(e) TransCanada Energy responses to AltaLink questions on Exhibit 271, filed on May 20,
2009; and


Please review this information before the next working group meeting, if possible.
IN THE MATTER OF the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2,

IN THE MATTER OF the Electric Utilities Act, S.A. 2003 c. E-5.1

AND IN THE MATTER OF an application by AltaLink Management Ltd. for the approval of its revenue requirement, deferral and reserve accounts for the period commencing January 1, 2009 to December 31, 2010.

__________________________
Evidence
of
TransCanada Energy Ltd.

__________________________
March 6, 2009
Alberta Utilities Commission
I. INTRODUCTION

In this filing, TransCanada Energy Ltd. (“TransCanada”) provides evidence and recommendations addressing AltaLink Management Ltd.’s (“AltaLink”) proposed Management Fee, which is one component of AltaLink’s revenue requirement being applied for its 2009-2010 General Tariff Application (“GTA”). TransCanada’s evidence will demonstrate that AltaLink’s concerns respecting the need for a Management Fee can be better resolved by the addition of a Rider to the AESO Tariff in the AESO 2010 General Tariff Application (“AESO 2010 GTA”). The specific details of an AESO Rider that would address AltaLink’s concerns are described in this evidence.

II. PROPOSED ALTALINK MANAGEMENT FEE

1. Introduction

In Section 15 of its Application, AltaLink advocates for a new Management Fee on customer contributions as a part of its revenue requirement. AltaLink states that it is concerned about the substantial and growing amount of Contributions in Aid of Construction (“CIAC”) from customers. These CIAC amounts do not attract a return on investment.

TransCanada recommends that AltaLink should be directed to participate in the AESO 2010 GTA or a Commission-directed process where the investment levels, amortization of customer contribution, management fees and other mechanisms raised in the AltaLink Management Fee evidence can be better resolved than in this GTA.

2. Discussion

AltaLink has requested a Management Fee to compensate it for assets that do not earn a return on investment due to offsetting customer contributions. This Management Fee is a new charge, approval of which could set a precedent for AltaLink and for the other TFOs in Alberta. ATCO Electric Ltd. (“AE”) has also requested approval of a management fee in its 2009-2010 GTA, The Management Fee proposed by AltaLink is based on the return on equity of the capital that would have been required if the Customer Contribution had not been provided by the customer.
The details of the Management Fee are shown in Table 4 below.

Table 4: Proposed Management Fee

<table>
<thead>
<tr>
<th>AltaLink Transmission Costs</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>1  Proposed Management Fee (Pre-Tax)</td>
<td>$5,473,000</td>
<td>$7,004,000</td>
</tr>
<tr>
<td>2  Projected Annual Revenue (before Management Fee)</td>
<td>$244,934,000</td>
<td>$284,065,000</td>
</tr>
<tr>
<td>3  AltaLink Management Fee (%)</td>
<td>2.23%</td>
<td>2.47%</td>
</tr>
</tbody>
</table>

The Management Fees proposed by AltaLink and AE have a substantial impact on customers.\(^3\) In 2010, the combined Management Fees proposed by AltaLink and AE are estimated to be over $12 million for just two of the six TFOS.\(^4\) As described below, TransCanada has developed an alternative that addresses the concerns of AltaLink with less impact on customers.

3. Amortized Customer Contribution Rider

TransCanada is not persuaded that the implementation of a Management Fee is the appropriate way to resolve this matter in the long term. Rather, TransCanada believes that it would be preferable to implement an Amortized Customer Contribution Rider (“Rider I”) in the AESO’s 2010 GTA or in an early module of that GTA with AUC approval. TransCanada believes Rider I would better address the concerns raised by AltaLink regarding its growing CIAC amounts and the consequent reduction of capital investment upon which AltaLink can earn a return.

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\(^1\) AltaLink 2009 2010 GTA, Section 15, pages 36 and 37.
\(^2\) AltaLink 2009 2010 GTA, Section 15, page 37, Table 3
\(^3\) An argument could be made that the Management Fees could be charged to all ratepayers, but for this discussion, it has been assumed that customers who triggered a customer contribution and a corresponding Management Fee will pay the Management Fee through an AESO rate mechanism. If Management Fees are not attributed to individual AESO customers, then all AESO ratepayers will be negatively affected by the proposed Management Fee.
\(^4\) The estimate was calculated by adding AltaLink’s proposed Management Fee of $7,004,000 and ATCO Electric’s proposed Management Fee of $3,906,000.
Rider I, including the attached sample rate schedule in Appendix A, has been provided to illustrate the overall simplicity of this solution and its ability to address TFO concerns. In essence, the purpose of Rider I would be to restructure the customer contribution so that customer-related assets that the TFO constructs are included in rate base at cost. In order to keep other ratepayers whole, the customer would make payments through Rider I that would compensate the TFO for the customer-related asset it constructed, including a rate of return. The design of Rider I ensures that those costs are charged to the relevant customer and not to all ratepayers.

The specific details of Rider I and its potential advantages to customers and TFOs are as follows.

Characteristics of Rider I

1. The Amortization Rate in Rider I includes:

   (a) a monthly payment that returns to the TFO the cost associated with the customer-related facilities not covered by the AESO investment policy (“Customer Contribution”) and that would be calculated by dividing the cost by the amortization period.

   (b) a monthly payment of the return on any unamortized balances that would be calculated based on the TFO weighted average cost of capital (“WACC”), including the appropriate income taxes as approved by the AUC for the relevant period for the TFO that owns the asset.

   (c) Both payments in (a) and (b) would be flowed through Rider I to the TFO by the AESO.

2. Rider I would amortize the Customer Contribution over an amortization period based on the contract term for the Customer-related assets for Demand Transmission Service (“DTS”) customers. For Supply Transmission Service (“STS”) customers, the term would be at least 10 years but no longer than 20 years.

3. Rider I payments would be based on the WACC for each TFO and would therefore vary according to the WACC for the TFO that owns the asset providing service to the customer.
4. If the AUC had not rendered a decision regarding WACC for a particular TFO for the time period that Rider I were to be applied, the previously approved WACC would be used on an interim basis. The final approved WACC for the relevant time period would be used to adjust the Rider I payments to a final amount, with the difference being refunded or charged to the customer. Any components of the WACC that are handled in deferral accounts, following approval of the AUC, would be adjusted in a similar fashion.

5. Rider I would only be available for creditworthy customers as determined by the AESO in their sole discretion. Security, such as a letter of credit, would be held by the AESO.

6. Customers would have the option to pay the Customer Contribution or could apply for a Rider I repayment of the Customer Contribution at the time of interconnection.

7. Rider I would be available for all AESO Customers who meet the qualifications for Rider I, such as STS customers and DTS customers, including Distribution Utilities (“DISCOs”).

8. From a default perspective, the assets covered by Customer Contribution payments would be treated in the same manner as assets covered by the AESO investment policy.

9. Unamortized balances of existing contributions could be converted to Rider I on a one time basis at some point after Rider I is approved and with the approval of the TFO and AESO at those parties’ sole discretion.

10. Contributions for Prepaid Operations and Maintenance charges would be treated in the same way as a customer contribution for capital costs and would be subject to Decision 2007-106, noting that the treatment of Prepaid Operations and Maintenance is currently before the Commission as a Review and Variance of Decision 2007-106.

11. Customer contributions to be refunded according to Article 9.9 of the AESO Terms and Conditions would reflect the amortization of the customer contribution achieved by Rider I and would be the basis of determining the unamortized contribution if required for an adjustment.
Potential Advantages to Customers/Ratepayers

1. Customers would not have to pay the proposed Management Fee as currently structured, which in 2010 is estimated to be over $12 million for AltaLink and AE, just two of the six TFOS. The proposed Management Fee would apply to everyone who has a customer contribution, including DTS customers served by DISCOs, any direct connect DTS customers who have customer contributions, and STS customers with customer contributions for their transmission interconnection costs. While DISCOs flow through transmission charges to their downstream customers, it is expected that DISCOs will also want to minimize costs that impact their customers to the extent that they can.

2. Since Rider I is only available to creditworthy customers and creditworthiness would be determined in the sole discretion of the AESO, the likelihood of default is substantially reduced. Customers who lack creditworthiness can provide security through different mechanisms, such as a letter of credit from a financial institution. The intent of Rider I is that there be a very low probability of impact on the costs paid by other AESO customers when an AESO customer passes the creditworthiness test and exercises the Rider I option. In the rare event that an AESO customer defaults on its payments, there is a high likelihood that whoever ends up owning the asset in the longer term will still need power to operate the facility supplied by the point of delivery. That new entity would continue the payments of the previous owner. Points of delivery on the transmission system are typically large and either supply towns or cities through the DISCOs or larger industrial facilities such as gas plants, refineries and compressor stations. While the owners of these facilities may experience financial difficulties, the facilities themselves are usually acquired by other companies who continue to use the facilities which in turn require electricity to operate.

3. For AESO customers who have a higher cost of capital than the TFOs, there will be a saving in the customer’s cost of capital.

4. For AESO customers who want to minimize their capital requirements, Rider I provides an option for monthly payments.

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5 The saving was calculated by adding AltaLink’s proposed Management Fee of $7,004,000 and ATCO Electric’s proposed Management Fee of $3,906,000.
5. The AESO could review Rider I in its next GTA and other residual issues could be dealt with at that time. It is expected that other customers will be minimally affected by this option.

6. A single AESO rider approach will provide regulatory efficiency and consistency throughout Alberta.

Potential Advantages to TFOs

1. A TFO will have the opportunity to avoid the reduction to its rate base arising from customer contributions and will have the ability to earn a return on the total investment in assets devoted to utility service.

2. As noted above under item 9 of “Characteristics of Rider I”, there could be a one-time option to convert unamortized balances of existing contributions when Rider I comes into effect. The TFO rate base could be increased accordingly if AESO customers who have historically been required to make a contribution have the option of converting the unamortized portions of their customer contributions to Rider I.

3. In acquiring the above benefits, TFOs will not be required to assume any additional risk under the Rider I proposal. Since Rider I is structured as an AESO Rider, the risk of default will be treated the same as other transmission system assets.

4. The impact of the Rider I approach can be reviewed at the next GTA of each TFO. If concerns should arise that Rider I is not working as intended, there will be an opportunity for the TFO to pursue a further remedy in the matter.

5. The AESO will also review Rider I in the AESO GTA following the AESO 2010 GTA and residual issues, if any, can be dealt with at that time.
4. Industry and AESO Perspective

AltaLink led a stakeholder working group with presentations to other attendees during 2008 to review the AESO Customer Contribution Policy. The recommendations from that initiative were provided to the AESO on November 21, 2008. Recommendation 7 was to provide “the choice for the contribution payment to be a facilities charge rather than a balance sheet transaction.” Recommendation 7 included the following elaboration:

The Working Group recommends that the AESO Investment Policy should include an option for the contribution to be set up as an AESO tariff payment determined by the TFO cost of service method including income tax, applied over the DTS/STS contract term. The contribution structured as an AESO tariff payment would be made available to any creditworthy customer. The attractiveness of the AESO Tariff Option to the customer will depend on the customer’s IRR and other factors including the customer’s election for treatment of the transaction on their balance sheet. The customer/POD specific AESO tariff Payment Option, or what has been referred to as a Facilities Charge Agreement, is not a new concept and has been applied successfully to specific PODs in the past. The adoption of the aforementioned eliminates the need for [a] customer to deploy large amounts of capital for facilities that they will not own and operate.

Only one participant in the working group indicated opposition to the proposal.

After reviewing the recommendations, the AESO included six of the eight recommendations, including recommendation 7, in its stakeholder consultation process for its 2010 GTA. While the AESO’s stakeholder consultation process is not complete, based upon the responses of participants in the working group, TransCanada expects significant support for such a proposal in the AESO 2010 GTA.

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7 Attendees included representatives from AFREA, AUMA, AUC, City of Lethbridge/Red Deer, UCA and Stephen Johnson Chartered Accountants.
8 Recommendations for Change – AESO GTA – Customer Contribution Policy submitted to AESO on November 21, 2008, page 1
9 Ibid, pages 10-11
10 Ibid, Appendix B-6
11 AESO letter to AESO Stakeholders, dated February 5, 2009, page 1 of 6 of AESO Preliminary List
5. Concluding Comments

In summary, TransCanada believes that the Rider I solution represents a better way to resolve the concerns identified by AltaLink as the reason a Management Fee is required. As a result, TransCanada submits that the concerns raised by AltaLink in respect of its proposed Management Fee would be better dealt with in the AESO 2010 GTA or other Commission-directed process.
APPENDIX A – Amortized Customer Contribution Rider

Alberta Electric System Operator
AESO 2007 Tariff
Effective November 1, 2008
[Unapproved] Rate Schedules and Riders

Rider I    Amortized Customer Contribution Rider

1 Purpose: To convert a lump-sum Customer Contribution to a monthly payment

2 Applicable to: Customers requesting conversion to a monthly payment who, in the sole discretion of the AESO, are creditworthy or able to meet AESO securitization requirements.

3 Effective: The rider is effective for all billing periods from January 1, 2009 onward.

4 Rate: The Amortization Rate includes:

5 (a) a monthly payment of the return of the original Customer Contribution and will be calculated by dividing the original Customer Contribution by the amortization period.

6 (b) a monthly payment of the return on any unamortized balances and will be calculated based on the TFO weighted average cost of capital (“WACC”) approved by the Alberta Utilities Commission (“AUC”) for the relevant period for the TFO that owns the asset.

7 The TFO WACC will be based on the WACC most recently approved by the AUC for the relevant period for the TFO that owns the asset. If a WACC is approved after the billing period that is applicable to the billing period, the difference in rate for each customer will be adjusted through a deferral account.

8 The amortization period will be based on the contract term for investable assets.

9 Terms: The Terms and Conditions form part of this Rate Schedule.
ASBG/PGA-TCE 1

Topic: Proposed AESO Rider I

Reference: Page 3 of 8 and 7 of 8

Preamble: 2. Rider I would amortize the Customer Contribution over an amortization period based on the contract term for the Customer-related assets for Demand Transmission Service (“DTS”) customers. For Supply Transmission Service (“STS”) customers, the term would be at least 10 years but no longer than 20 years.

AltaLink led a stakeholder working group with presentations to other attendees during 2008 to review the AESO Customer Contribution Policy.

Request:

(a) For customers serviced by the AML TFO currently what is the average percentage of the interconnection investment for DTS customers that is covered by a Customer Contribution for this class of customer?

(b) Currently the upfront Customer Contribution for STS customers covers the entire interconnection investment for this class of customer. Does the Rider I proposal effectively release the STS customers obligation for a one time upfront Customer Contribution in the amount of their total interconnection cost to a potential annual amortization payment of up to 20 years.

(c) With DTS customers responsible for all transmission costs why should STS customers be availed the same amortization option as DTS customers.

Response:

(a) TransCanada does not have access to this customer specific information of AltaLink Management Ltd. (“AltaLink”). TransCanada’s intention in advancing the Rider I proposal is to offer an alternative to the proposed AltaLink Management Fee to illustrate for the Commission another potential solution to the concern raised by AltaLink.
Rider I is not being advanced for approval in this proceeding. Specific design features of the Rider I alternative will be reviewed in the AESO 2010 General Tariff Application (“GTA”), along with opportunities to obtain supporting factual information such as that requested in this question. In the present proceeding, TransCanada will provide as much detail as practical under the circumstances in relation to the alternative, recognizing that the features and details of Rider I will be dealt with in the AESO 2010 GTA. This limitation applies generally to all of the responses to ASBG/PGA information requests.

(b) The STS customer is not necessarily released from its obligation to make a one time upfront Customer Contribution. In the Rider I proposal, STS customers will have the option of either making a one time upfront Customer Contribution or applying for Rider I treatment. If a STS customer applies for Rider I treatment, the AESO, in its sole discretion, will consider whether the STS customer is sufficiently creditworthy to make Rider I payments. If the STS customer is not deemed creditworthy, then the STS customer will be required to make an upfront Customer Contribution.

(c) AltaLink’s concerns regarding owning assets for which it is unable to obtain a return is applicable to both DTS and STS customers.

Further, DTS customers are not responsible for all transmission costs. It should be noted that:

- STS customers pay 100% of the cost of facilities required to interconnect with the AIES and meet its STS Capacity requirements.\(^1\)
- PPA generation is not required to make a Customer Contribution, but currently pays a monthly charge for interconnection for Regulated Generating Unit Connection Costs.
- STS customers are also responsible for almost all transmission losses.
- STS customers are required to pay any System Contribution cost that may be required under Article 9.11(b) of the AESO Terms and Conditions. However, TransCanada notes that Rider I is not intended to apply to System Contributions.

As a result of the foregoing, STS customers should be availed the same amortization option as DTS customers. Furthermore, the Rider I proposal places STS customers who meet the AESO’s creditworthiness test on a more level playing field with PPA generation.

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\(^1\) AESO Terms and Conditions, Article 9.11 (a). Contributions may be modified where a facility is also used for DTS customer loads: Articles 9.3, 9.5 and 9.6.
ASBG/PGA-TCE 2

Topic: Proposed AESO Rider I

Reference: Pages 3 and 4 of 8

Preamble: 3. Rider I payments would be based on the WACC for each TFO and would therefore vary according to the WACC for the TFO that owns the asset providing service to the customer.

4. If the AUC had not rendered a decision regarding WACC for a particular TFO for the time period that Rider I were to be applied, the previously approved WACC would be used on an interim basis. The final approved WACC for the relevant time period would be used to adjust the Rider I payments to a final amount, with the difference being refunded or charged to the customer. Any components of the WACC that are handled in deferral accounts, following approval of the AUC, would be adjusted in a similar fashion.

Request:

(a) Where customers are required to provide a customer contribution for interconnection please discuss whether the AESO would have to calculate a Rider I payment on a monthly basis for each DTS transmission direct connect customer, each DTS Disco customer by TFO POD, and each STS customer and also recognize the specific contract term for each of these customers.

(b) Please discuss the proposed Rider I impact on the AESO deferral account and reconciliation process if the Rider I calculations are customer specific.

(c) Please compare and discuss the administrative complexity of the proposed AESO Rider I methodology with the existing AESO Customer Contribution policy requirements.

Response:

(a) Please refer to the response to ASBG/PGA-TCE 1(a).
The calculations described would be required for DTS transmission direct-connect customers to the extent they have a Customer Contribution, which many do not. The same applies to DTS DISCO customers for those TFO PODs that have a Customer Contribution. Again, many do not. Most, if not all, STS customers other than PPA Generators would have a Customer Contribution with calculations as described.

(b) and (c):

Subject to its response to ASBG/PGA-TCE 1(a), TransCanada anticipates there will be some additional administration required by the Rider I as compared to the existing administration of the AESO Customer Contribution policy, but TransCanada does not expect it to be significant for either the AESO or TFOs. TransCanada believes the more appropriate comparison is with the administration that would be involved in the implementing the proposed Management Fee. Firstly, should the Management Fee be approved, TransCanada anticipates that there would be a significant regulatory burden associated with how the Management Fee will be allocated among AESO customers and among DISCO customers for costs charged to each DISCO. In addition, if the Management Fee is assigned to specific customers, then there will be a similar level of incremental administration as for Rider I.

TransCanada understands that the Rider I proposal would first require the AESO to perform a creditworthiness test for DTS or STS customers requesting Rider I treatment. The AESO is already conducting such tests as a part of its interconnection process, so the incremental cost for this step should be minimal.

Second, if the applicant passes the creditworthiness test, then the AESO would need to convert the Customer Contribution into a monthly payment. In the case where the Weighted Average Cost of Capital (“WACC”) for the TFO is not yet finalized, the AESO would use the previously-approved WACC to determine Rider I charges until the final WACC is approved by the Commission. Once a WACC is determined, the differences can be adjusted in the customer’s bill for Rider I. While no further adjustments may be required, if there are any residual differences arising from Deferral Account Adjustments, they can be adjusted in the Deferral Account Adjustment proceeding. The Deferral Account process already takes into account every POD and POS in the province and must make adjustments on a customer-specific basis. Again, TransCanada does not anticipate that the administration required would be significantly different than that required for the Management Fee, particularly if the Management Fee is administered on an individual customer basis.
From the TFO perspective, there will be a small increase in administrative burden to manage the Rider I proposal as compared with the status quo because TFOs will be required to manage monthly payments rather than a single contribution payment.
ASBG/PGA-TCE 3

Topic: Proposed AESO Rider I

Reference: Page 4 of 8

Preamble: 5. Rider I would only be available for creditworthy customers as determined by the AESO in their sole discretion. Security, such as a letter of credit, would be held by the AESO.

Request:

(a) Please compare and discuss the risk of an upfront DTS Customer Contribution and annual payments for contract terms of 20 years and greater.

(b) Please compare and discuss the risk of an upfront STS Customer Contribution for 100% of transmission interconnection costs and annual payments for contract terms of 20 years.

(c) Please discuss what other types of security were considered other than a letter of credit.

(d) Please discuss how the incremental costs associated with reviewing and monitoring these security arrangements would be accounted for and recovered from DTS and STS customers.

Response:

(a) and (b):

Please refer to the response to ASBG/PGA-TCE 1(a).

TransCanada anticipates that there is minimal risk of a default on payments by either DTS or STS customers that would result in other customers bearing any material cost. The reasons for this conclusion will be elaborated below. To place this risk in context, it should be compared with the AltaLink Management Fee proposal that would cost, if approved, $7 million in 2010. Also, the Management
Fee will increase as Customer Contributions increase. In this context, TransCanada believes the savings in annual costs that can be achieved through Rider I outweigh the risk of default for the system as a whole.

There is currently minimal risk of default in relation to either DTS or STS Customer Contributions that are paid prior to commencement of construction of transmission facilities. TransCanada believes that there is also a minimal risk of default by DTS and STS customers under Rider I for the following reasons:

1. Rider I is designed so that only creditworthy DTS or STS customers can convert their Customer Contribution into a Rider I monthly payment. TransCanada recommends that at least the same level of scrutiny applied to customer creditworthiness per AESO Terms and Conditions Article 15.1 should be applied to Customer Contributions to be converted to Rider I payments.

2. Loads supplied at the transmission level tend to be very large, usually at least 5 MW. If the facilities are required to serve towns or rural areas with large amounts of residential, commercial and small industrial customers, a DISCO is involved and there is almost no risk that the DISCO will default on its payments for those facilities. Even if the DISCO did go bankrupt, the DISCO assets would be taken over by another utility that would be in a position to pay for the transmission assets. Similarly, facilities to serve large industrial loads are typically the result of very large investments where the electricity supply is only one minority component of their cost structure. In most circumstances, were a DTS customer to encounter financial difficulty, TransCanada would expect the industrial load to be taken over by a purchaser who will continue to make payments to obtain DTS service.

3. STS contracts are for a range of generation facilities for which the cost of transmission is small compared to the cost of the facility. Due to the value of these plants in the supply of energy, these plants are likely to be purchased and would continue to operate in the event of financial difficulties of an owner.

4. Should all these mitigating factors fail, there are still some further mitigating factors that reduce the exposure to other customers. First, to the extent that the customer defaults on its payments part way through the contract term, the payments prior to the default event have reduced the amount of stranded cost exposure to other customers. Second, a portion of the value of the facilities can be sold or moved to useful service elsewhere. For example, transformers are a significant portion of the cost of substations, have long physical lives.

1 Note that DTS contract terms are 5 to 20 years per AESO T&Cs, Article 9.6 (b).
2 Any smaller than this size and the load will likely be supplied from the Distribution System.
and can almost always be reused or sold, often at a price near or even higher than the original cost.

(c) TransCanada did not consider any types of security beyond those included as a part of the AESO’s Credit Requirements as described in AESO Terms and Conditions Article 15.1.

(d) The AESO already must monitor the creditworthiness of DTS and STS customers as a part of AESO Terms and Conditions Article 15.1. Therefore, the incremental cost to review and monitor security arrangements is expected to be minimal. TransCanada does not propose any change in how these costs are accounted for at the present time.
ASBG/PGA-TCE 4

Topic: Proposed AESO Rider I

Reference: Page 4 of 8

Preamble: 7. Rider I would be available for all AESO Customers who meet the qualifications for Rider I, such as STS customers and DTS customers, including Distribution Utilities (“DISCOs”).

Request:

If the STS contract term is limited to 20 years could a dual-use STS/DTS customer have different contract terms for STS and DTS customer contributions?

Response:

Yes. As long as the Customer Contribution amounts assigned to the STS customer and DTS customer are appropriately allocated, there is no need for the contract terms to be the same.
Preamble:

8. From a default perspective, the assets covered by Customer Contribution payments would be treated in the same manner as assets covered by the AESO investment policy.

Request:

(a) Please describe the current treatment of assets covered by Customer Contribution payments for a DTS customer on the default of such customer and provide an illustrative example. With the Rider I methodology what is proposed for the recovery of the Customer Contribution obligation on the DTS customer default.

(b) Please describe the treatment of assets covered by Customer Contribution payments for a STS customer on the default of such customer and provide an illustrative example. With the Rider I methodology what is proposed for the recovery of the Customer Contribution obligation on the STS customer default and discuss the impact of the obligation being 100% of the interconnection cost.

Response:

(a) and (b):

Please refer to the response to ASBG/PGA-TCE 1(a).

There is minimal default risk in the current treatment of assets covered by Customer Contribution payments for DTS and STS customers since these payments are required before the start of construction of the transmission facilities\(^1\) and financial security requirements of the AESO are in place.\(^2\) Regarding the Rider I methodology, please refer to the response to ASBG/PGA-TCE 3 (a). In either case, in the rare cases where defaults occur, any

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\(^1\) Refer to AESO Terms and Conditions, Article 9.2.
\(^2\) Refer to AESO Terms and Conditions, Article 15.1.
stranded costs would generally be recovered through the TFO revenue requirement submitted to the AESO for recovery through AESO rates.
ASBG/PGA-TCE 6

Topic: Proposed AESO Rider I

Reference: Page 4 of 8

Preamble: 9. Unamortized balances of existing contributions could be converted to Rider I on a one time basis at some point after Rider I is approved and with the approval of the TFO and AESO at those parties’ sole discretion.

Request:

(a) Please describe the current accounting processes for Customer Contributions by the AESO and TFOs and whether such Customer Contributions and amortizations are maintained on a customer specific basis for both DTS and STS customers.

(b) In accordance with the proposed Rider I methodology and monthly amortizations please describe any required changes to accounting processes for both the AESO and the TFOs to accommodate the methodology.

Response:

(a) Please refer to the response to ASBG/PGA-TCE 1(a). TransCanada is unable to speak to accounting processes at the AESO and TFOs.

TransCanada understands that these contributions are maintained on a customer specific basis by both the AESO and TFO.

(b) Please refer to the response to (c) above.
Potential benefits to customers/ratepayers

1. Customers would not have to pay the proposed Management Fee as currently structured, which in 2010 is estimated to be over $12 million for AltaLink and AE, just two of the six TFOS. The proposed Management Fee would apply to everyone who has a customer contribution, including DTS customers served by DISCOs, any direct connect DTS customers who have customer contributions, and STS customers with customer contributions for their transmission interconnection costs.

Request:

(a) Please describe any benefits or potential harm to existing or future DTS customers that are not required to provide any Customer Contributions.

(b) Would the largest benefit be to existing and future STS customers that are responsible for 100% of their transmission interconnection costs?

Response:

(a) The effects of Rider I must be compared to those arising from the Management Fee proposal, not the status quo. The impact of the Management Fees on existing or future DTS customers will depend on whether the Fees are allocated to all AESO customers or separated out and assigned to the AESO customers that paid the Customer Contribution and whether the Management Fee will be allocated to STS customers or whether those costs will flow to DTS customers pursuant to s. 47 of the Transmission Regulation. If the Management Fee is allocated to all AESO customers (whether solely DTS customers or DTS and STS customers), all DTS customers will be required to pay their allocated share of the Management Fee. In this case, the Rider I proposal will benefit DTS customers. If the Management Fee is assigned on a customer-specific basis, then DTS customers,
including direct-connect customers, that are not required to provide any Customer Contributions would not pay charges related to the Management Fee on Customer Contributions from a DTS customer, but may nevertheless be required to pay a portion of the Management Fee earned on Customer Contributions from an STS customer. Therefore, DTS customers will either be better off or neutral if Rider I were implemented, other than the very low probability of a long-term default on payment of a Customer Contribution. Refer also to the response to ASBG/PGA-TCE 3.

If the Commission determines that the Management Fee is to be assigned to the AESO customer paying the Customer Contribution, DISCO customers, including ASBG/PGA customers, may end up paying a portion of the Management Fee. The reason is that the Management Fee for specific DISCO interconnections may become a part of the DISCO revenue requirement and could be allocated to all DISCO customers. In this case, the benefit of the Rider I proposal is the avoidance of the DISCO share of the Management Fee.

(b) TransCanada cannot provide a general statement on whether the largest benefit of Rider I will be to existing and future STS customers. The most important point to note is that with the risk of default reduced to a very low level through AESO creditworthiness requirements and other practical considerations described in ASBG/PGA-TCE 3, then all DTS and STS customers are either better off or neutral under the Rider I proposal compared to the AltaLink Management Fee proposal.

With respect to STS customers specifically, a large amount of existing STS customer supply is under PPA generation that already have the benefit of making monthly payments for interconnection costs through the Regulated Generating Unit Connection Costs payments (i.e. no customer contribution was required). For other STS customers, the benefits of the Rider I proposal will depend on several factors including the cost of their interconnection, what portion of that cost remains unamortized, their need to reduce capital commitments and their cost of capital. Therefore, the benefits for the remaining STS customers could vary from no benefit to a significant benefit.
ASBG/PGA-TCE 9

Topic: Proposed AESO Rider I

Reference: Page 5 of 8

Preamble: In the rare event that an AESO customer defaults on its payments, there is a high likelihood that whoever ends up owning the asset in the longer term will still need power to operate the facility supplied by the point of delivery.

Request:

(a) Please describe the consequences to other AESO customers if a STS customer defaults on its payments.

(b) Please address the issue of potential customer defaults in terms of the present economic downturn in Alberta and the rest of North America.

Response:

(a) Please refer to the responses to ASBG/PGA-TCE 3 and ASBG/PGA-TCE 5.

(b) Since Rider I is only available to creditworthy customers, it is expected that the AESO will decline a request for Rider I treatment if they are concerned about the long-term economic viability of a given customer. Please refer to the response to ASBG/PGA-TCE 3.
ASBG/PGA-TCE 10

Topic: Proposed AESO Rider I

Reference: Page 6 of 8

Preamble: 6. A single AESO rider approach will provide regulatory efficiency and consistency throughout Alberta.

Request:

Please describe the regulatory efficiencies when it is understood that a new additional AESO rider is proposed that would be customer specific in terms of costs and contract term and would be subject to the AESO deferral account and reconciliation process.

Response:

Please refer to the response to ASBG/PGA-TCE 1(a).

The comment in the Preamble was made in the context of a comparison of Rider I to the proposed Management Fee.

Both ATCO Electric and AltaLink have applied separately for Management Fees as part of their 2009-2010 GTAs, and so have already required fairly significant regulatory resources of the applicant, AUC and interveners to address the request. Such requirements would also be the case for the other four TFOs, assuming they also decided to apply for a Management Fee.

While TransCanada recognizes that an additional regulatory proceeding will be required to approve and implement Rider I, it is preferable to multiple separate regulatory applications in which the concern raised by the TFOs will be dealt with on a piecemeal basis. Rider I would deal with the TFO concerns in a single proceeding that would be applicable to all TFOs and result in the implementation of a consistent solution across the province.

In addition, if the the Management Fee is approved, this decision will trigger regulatory debates in future AESO GTAs to decide which customers will have to pay the
Management Fee. Similar issues will arise in the DISCO hearings to allocate these charges from the AESO in the DISCO rate design process. TransCanada understands that Rider I is a more generally acceptable solution within the industry, as it is the result of the AltaLink working group deliberations reflected in the response to AUC-TCE 1.

With respect to deferral accounts and reconciliation, it should be noted that the AESO already deals with customers on an individual basis in deferral account proceedings.
ASBG/PGA-TCE 11

Topic: Proposed AESO Rider I

Reference: Page 6 of 8

Preamble: 3. In acquiring the above benefits, TFOs will not be required to assume any additional risk under the Rider I proposal. Since Rider I is structured as an AESO Rider, the risk of default will be treated the same as other transmission system assets.

Request:

(a) If a specific DTS customer serviced by a TFO is in default please describe the treatment and impact on the TFO, other customers of the TFO, the AESO and other TFOs in the province. Please describe what changed impacts would occur if the proposed Rider I methodology was in place.

(b) If a specific STS customer serviced by a TFO is in default please describe the treatment and impact on the TFO, other customers of the TFO, the AESO and other TFOs in the province. Please describe what changed impacts would occur if the proposed Rider I methodology was in place.

Response:

(a) and (b):

The request requires information regarding AESO and TFO accounting and other practices that goes beyond TransCanada’s firsthand knowledge. For a general discussion of DTS and STS customer default, please refer to the responses to ASBG/PGA-TCE 3 and ASBG/PGA-TCE 5.
Topic: Proposed AESO Rider I

Reference: Industry and AESO perspective, page 7 of 8

Preamble: “The customer/POD specific AESO tariff Payment Option, or what has been referred to as a Facilities Charge Agreement, is not a new concept and has been applied successfully to specific PODs in the past. The adoption of the aforementioned eliminates the need for [a] customer to deploy large amounts of capital for facilities that they will not own and operate.”

ASBG/PGA note the prime benefit of the proposal appears to be that DTS and STS customers that are currently required to provide an upfront Customer Contribution will not be required to deploy large amounts of capital for these contributions pursuant to the Rider I methodology. Additionally ASBG/PGA understand that existing DTS and STS customers with customer contributions may elect to transfer to the new Rider I methodology and receive a refund of the unamortized portion of prior contributions.

Request:

(a) To better understand the potential impact of the Rider I proposal please provide AML’s:
   - original customer contribution balance at December 31, 2008,
   - the cumulative amortized customer contribution balance at December 31, 2008,
   - the forecast customer contributions for each of 2009 and 2010
   - the forecast customer contribution amortizations for each of 2009 and 2010

(b) On the assumption that the Rider I methodology was in effect January 1, 2009 and all new customers and existing DTS and STS customers converted to the new methodology please quantify the additional capital that the AML TFO will have
to raise for each of 2009 and 2010 pursuant to a) above. Please apply the AML forecasted cost of new capital for 2009 and 2010 to determine the additional financing costs associated with the Rider I methodology for 2009 and 2010 and provide all calculations.

(c) From the additional financing costs determined in (b) above please add amortization and income taxes to determine the additional revenue requirement impact for 2009 and 2010 and provide all calculations.

(d) Please describe any other alternatives to the proposed annual charge that were considered in the AltaLink working group during 2008 and why these alternatives were rejected.

Response:

(a) to (c):

TransCanada has provided estimated responses to the requests in Table ASBG/PGA-TCE 12 below using data from Schedule 7.6 from the AltaLink January 27, 2009 Amendment.

<table>
<thead>
<tr>
<th>Line no.</th>
<th>Description</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Original customer contribution balance at December 31</td>
<td>$143.2</td>
<td>$150.5</td>
<td>$154.9</td>
</tr>
<tr>
<td>2</td>
<td>Cumulative amortized customer contribution balance at December 31</td>
<td>$19.4</td>
<td>$24.3</td>
<td>$29.4</td>
</tr>
<tr>
<td>3</td>
<td>Forecast customer contributions</td>
<td>$32.9</td>
<td>$7.3</td>
<td>$4.4</td>
</tr>
<tr>
<td>4</td>
<td>Forecast customer contribution amortizations</td>
<td>$4.2</td>
<td>$4.9</td>
<td>$5.1</td>
</tr>
<tr>
<td>5</td>
<td>New capital for Rider I customers (if all customers convert to Rider I on January 1, 2009)</td>
<td>$133.5</td>
<td>$4.4</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Cost of capital (%)</td>
<td>6.901%</td>
<td>7.018%</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Cost of capital ($) (line 5 times line 6)</td>
<td>$9.2</td>
<td>$0.3</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Income taxes ($) unadjusted for CCA Claim</td>
<td>$1.3</td>
<td>$0.0</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Total Revenue Requirement impact before Rider I revenues</td>
<td>$15.4</td>
<td>$5.5</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Total Revenue Requirement impact after Rider I revenues</td>
<td>$0.0</td>
<td>$0.0</td>
<td></td>
</tr>
</tbody>
</table>

1 For 2009, new capital calculated by subtracting line 2 from line 1 and adding line 3 in the 2009 column. For 2010, new capital is taken from line 3 in the 2010 column.
2 Cost of capital for 2009 obtained from Schedule 4.1.2009 (i) and for 2010 from Schedule 4.1.2010 (i) from AltaLink January 27, 2009 Amendment.
3 Income taxes based on 29% in 2009 and 28% in 2010, with no adjustments for CCA Claim. Equity return of 8.75% and capital structure with 38% equity for 2009 and 2010 based on Schedules 4.1.2009 (i) and 4.1.2010 (i) from AltaLink January 27, 2009 Amendment.
4 Total Revenue Requirement was calculated by adding line 4 + line 7 + line 8.
It should be noted that the revenue requirement impact, net of Rider I revenues, is zero. The reason for this is that the Rider I revenues are designed to completely offset the revenue requirement associated with the Customer Contribution.

(d) Another option that was examined in the AltaLink working group was whether each TFO could finance the customer contributions in an arrangement between the Customer and the TFO. This arrangement was rejected as it left the TFOs with default risk, although quite small, for which they would have to charge a large risk premium on the return component of the costs in the absence of a large pool of customers to manage that risk. If the cost of capital became too high, customers would opt to finance the Customer Contributions themselves and the objective of restoring the TFO rate base would be lost.
ASBG/PGA-TCE 13

Topic: Proposed AESO Rider I

Reference: Appendix A, page 1 of 1

Preamble: Amortized Customer Contribution Rider

Request:

(a) Please describe the recognition and treatment of O and M expenses associated with the Customer Contribution assets for each of DTS and STS customers. Please include a discussion of the use of pre-paid O and M expenses for these customers.

(b) Please fully explain the treatment of dual-use customers as both DTS and STS customers in the determination of Customer Contributions and the proposed amortization of the associated Customer Contributions with illustrative examples.

(c) Please discuss the additional administrative and other costs associated with the proposed Rider I methodology as compared to the status quo and the customer cost responsibility for these additional costs.

Response:

(a) The material requested goes beyond the scope and purpose of TransCanada’s evidence on Rider I and is not relevant to the matters to be decided by the Commission in this proceeding. Please refer to the response to ASBG/PGA-TCE 1(a).

(b) Please refer to the response to ASBG/PGA-TCE 1(a). TransCanada does not propose any change to the determination of Customer Contributions for dual use customers. Once the Customer Contribution has been determined, dual use customers will be able to elect whether or not to use Rider I.

(c) Please refer to the responses to ASBG/PGA-TCE 1(a), ASBG/PGA-TCE 2(c), ASBG/PGA-TCE 3(d), and ASBG/PGA-TCE 10.
THE CHAIR: Good morning, Ms. Duffy.

Welcome to the front of the room.

Ms. Berge, good morning. Mr. Unryn, good morning. Good morning to you. Good morning to everybody that's out there this morning. I'm going to try to lighten it up a little bit this morning, but it just didn't come to me. That would be you, Ms. Duffy. So go ahead.

MS. DUFFY: I don't know if I have any jokes in my back pocket either. So good morning, Mr. Chairman, Commission Members.

Seated before you are the TransCanada Energy Limited witnesses. Closest to you is Mr. Vince Kostesky, and beside him is Mr. Dan Levson.

I would ask that the witnesses be sworn at this time.

THE CHAIR: Thank you, Ms. Duffy.

V. KOSTESKY, D. LEVSON (For TransCanada Energy Limited) sworn, examination in chief by Ms. Duffy:

MS. DUFFY: Their CVs having filed as Exhibit Number 29, and I don't propose to introduce them further.

Q. So, Mr. Kostesky and Mr. Levson, do you have before
you TransCanada's evidence, which is Exhibit 94, TransCanada's information responses, which are Exhibits 110 and 111, as well as your CVs, which are Exhibit 129?

A. MR. KOSTESKY: I do.

A. MR. LEVSON: I do.

Q. Were these exhibits prepared by you or under your direction and control, Mr. Kostesky?

A. MR. KOSTESKY: Yes, they were.

Q. And Mr. Levson?

A. MR. LEVSON: Yes.

Q. Do you have any corrections to make to these exhibits?

A. MR. KOSTESKY: Yes, I have two corrections. The first one is on page 4 of TransCanada's evidence, which is Exhibit 94. At line 9 of page 4, the words "have the option to" should be struck, and the word "or" should be replaced with "and." Therefore, the revised sentence should read: "Customers would pay the customer contribution and could apply for Rider I repayment of the customer contribution at the time of interconnection."

I also have a correction to the footnote 5 found on page 5 of TransCanada's evidence in the same exhibit, number 94. I'd like to add the words "grossed up 28 percent for income taxes to $5,425,000" to the end of the footnote. Therefore, the revised footnote should read: "The saving was calculated by adding AltaLink's proposed
management fee of $7,004,000 and ATCO Electric's proposed
management fee of $3,000,906 grossed up 28 percent for
income taxes to $5,425,000."

Q. Given those corrections, are the exhibits true and
correct, to the best of your knowledge, Mr. Kostesky?
A. MR. KOSTESKY: Yes, they are.

Q. And Mr. Levson?
A. MR. LEVSON: Yes.

Q. Do you adopt these exhibits as TransCanada's evidence
in these proceedings, Mr. Kostesky?
A. MR. KOSTESKY: Yes, I do.

Q. And Mr. Levson?
A. MR. LEVSON: Yes.

Q. Thank you.

MS. DUFFY: Mr. Chairman, TransCanada's
opening statement was filed on -- I believe it was Tuesday,
with Commission staff and circulated to all the parties,
and there is paper copies at the back of the room.
I believe we need an exhibit number for the
opening statement.

THE CHAIR: Ms. Duffy, we could, and
let's use Exhibit Number 256.

EXHIBIT 256 - OPENING STATEMENT OF TRANSCANADA
ENERGY.

MS. DUFFY: If it's acceptable to the
Commission, I would ask that Mr. Kostesky read the opening statement into the record at this time.

THE CHAIR: That's fine. Thank you.

A. MR. KOSTESKY: Good morning, Mr. Chairman and Commissioners. My name is Vince Kostesky, senior advisor, western power for TransCanada.

TransCanada has intervened in this proceeding to present an alternative to AltaLink's proposed management fee. This concept has been described as "Rider I" in TransCanada's evidence.

TransCanada expects a similar methodology to be advanced by the AESO in its 2010 GTA as a result of the recommendations regarding the customer contribution policy that was submitted by AltaLink on behalf of the working group.

CIAC is trending upward. While AltaLink and ATCO Electric are concerned about this trend, it is also a concern from a customer standpoint. Although CIAC amounts may represent no cost capital to the TFO, customers are required to raise increasingly significant lump sum contributions at the outset of a project.

These contributions are a material cost on the customer's books, but customers have no ownership or control of the asset.

Unlike the proposed management fee, the
Rider I alternative would address the concerns of both TFOs and customers. The cornerstones of the Rider I alternative are as follows:

Number 1: The Rider I payment would provide both a return of the TFO's capital as well as a return on the capital.

Number 2: Rider I would provide the customer the opportunity to make amortized payments over a specified period of time.

Number 3: Rider I payments would only be made by the customer causing the need for the contribution and therefore do not impact other ratepayers.

Number 4: Rider I would only be made available to creditworthy customers, and therefore the risk of default is minimal. As Rider I would be an AESO tariff provision, the AESO would look to its customers in the unlikely event of default.

Finally, number 5: Rider I would permit unamortized balances related to legacy assets to be converted to Rider I.

It is important to emphasize any such conversion would be at the sole discretion of the AESO and the TFO. Therefore, the TFO would determine whether or not it wished to take on these obligations based upon its own financial circumstances.
The proposed management fee would be a new annual charge that would be costly to customers. For 2010, AltaLink forecasts this new charge to be 5.6 million after tax or 7.8 million before tax. It is the before-tax figure that represents the actual annual impact to customers.

The Rider I alternative is less expensive to customers than the proposed management fee. In assessing the merits of the management fee proposal versus other alternatives, TransCanada encourages the Commission to consider actual cost to customers, not just the cost the utilities face.

With respect to Dr. Cicchetti's revised proposal regarding a combination of Rider I and a management fee, TransCanada believes that sufficient numbers of customers with CIAC amounts will qualify and opt for Rider I, so that the TFO's concern of having CIAC as a large percentage of their rate base will be addressed.

Completion of AltaLink's predicted major capital projects in the near future will also result in additions to rate base that will significantly reduce the amount of CIAC relative to total rate base.

Other factors, such as an increase in the transmission investment level and a possible change to prepaid operations and maintenance costs, will also reduce the levels of CIAC required on a go-forward basis.
TransCanada believes that Rider I and these other factors will adequately address the concerns of AltaLink by substantially lowering CIAC as a percentage of rate base. Therefore, it is premature to approve a management fee at this time.

TransCanada has attempted to provide as much detail as possible in order to demonstrate that the Rider I alternative is viable; however, TransCanada is not seeking approval of Rider I in this proceeding. The AESO has already advanced a Rider I-type proposal for consultation in its 2010 GTA, which TransCanada believes is the appropriate forum to determine the details and operation of Rider I.

However, if the Commission is of the view that the resolution of the concerns related to CIAC is urgently required, an early module of the AESO 2010 GTA or another Commission-directed process could be established.

In closing, TransCanada would like to thank the Commission for the opportunity to make these remarks and looks forward to responding to questions. Thank you.

MS. DUFFY: Thank you. The witnesses are now available for questioning.

THE CHAIR: Thank you, Ms. Duffy.

Mr. Unryn, I understand you're the only one that's having cross with this panel; is that correct?
MR. UNRYN: Mr. Chairman, Mr. Ross would --

THE CHAIR: Yes, Mr. Ross; I took that, yes, thank you. Sorry, Mr. Ross.

Go ahead, Mr. Unryn.

MR. UNRYN: Thank you very much, Mr. Chairman, Members of the Commission.

MR. UNRYN CROSS-EXAMINES THE PANEL:

Q. Good morning, panel.

A. MR. KOSTESKY: Good morning.

Q. Panel, first off, we heard your opening statement, and it's filed as Exhibit 256 in this proceeding. I wanted to address a few items in that opening statement. In the second paragraph of the opening statement, you address CIAC.

Now, TCE indicates, although CIAC amounts may represent no cost capital to the TFO, customers are required to raise increasingly significant lump sum contributions at the outset of a project. These contributions are a material cost on the customers' books, but customers have no ownership or control of the assets.

Now, panel, does the use of customers in this context primarily refer to transmission-connected customers?

A. MR. LEVSON: Yes.
Q. Yes, it does. Thank you, Mr. Levson.

Was the customer concern about raising significant lump sum contribution the major driver for the TC evidence on the Rider I proposal rather than the issue of no cost capital to the TFOs?

A. MR. LEVSON: A little bit of history on this might be helpful.

In the spring of 2008, AltaLink initiated a contribution policy working group, and one of the issues that was raised very early was the growing problem with the contributions. And so we began, in that context, with a good portion of industry present, looking at what are the options.

So the concept of Rider I -- it wasn't called Rider I at the time, but the same concept was discussed, along with other ways to resolve the problem.

So it was clearly the TFOs at that point in time that was the driving concern, the growing amount, and the no cost capital component of it.

As time went on and the management fee got introduced through the applications of the TFOs, both ATCO and AltaLink, and then I guess the pressure to come up with a solution increased and so we began fleshing out the Rider I proposal. TransCanada took the initiative on it in terms of organizing discussions and negotiating what it would
V. KOSTESKY, D. LEVSON  
- Cross-Examined by Mr. Unryn

1  look like.
2  So I don't know if that answers your
3  question or not.
4  Q.  Well, partially, Mr. Levson.  I think with your
5  opening statement, because you referenced the material cost
6  of customer contribution on the customer books, it appears
7  that that's a significant consideration in your --
8  A.  MR. LEVSON:  Absolutely.  And because that
9  process was looking at not just that problem that the TFOs
10  raised, it was also looking at how we were determining the
11  maximum investment level, because from a specific customer
12  perspective, whether it's a DFO customer or industrial
13  customer, you're looking at really large contributions
14  compared to what we had experienced in the past.  And that
15  went to a couple of factors.  One was the fairly rapidly
16  escalating cost and then an investment policy that just
17  didn't seem to be able to keep up with it.
18  So we get this growing gap between what it's
19  costing to build facilities and how much is being invested
20  in the system -- or in the tariff, through the maximum
21  investment level.  And the difference with growing up -- so
22  we as commercial were motivated to try to come up with a
23  solution.
24  So this is an issue that's better addressed
25  in an AESO matter proceeding because the investment level
is tied to the cost -- in all of the TFOs costs. So it's awkward to be dealing with this matter here, but the management fee was what brought us here.

Q. Okay, sir. But --

A. MR. KOSTESKY: Could I just add something to that as well?

Q. Yes.

A. MR. KOSTESKY: Talking about the material costs in the customers' books. According to AltaLink's rebuttal, which I believe -- I don't have an exhibit number on it, but in table 1 of Dr. Cicchetti's rebuttal, in 2010, the CIAC amount would be just under $230 million. And we view that as a substantial amount that is on the TFO's books that is not in the customers' account to be able to invest in their core businesses. So it's raising to a substantial level as well in absolute dollars.

Q. So to follow up on that, then, that is a major concern, then, of TCE in developing this proposal?

A. MR. KOSTESKY: Yes, I don't know if I would agree that it's a major concern, but it is an increasing concern.

Q. Thank you. Now, back to the opening statement. When TCE indicates that customers have no ownership of the asset, the AESO does have a primary service credit that addresses facilities that are owned by the customer and for
which a credit is provided. Is my understanding correct there, sir?

A. MR. LEVSON: Yes. If a customer such as TransCanada or, say, a large industrial customer chose to own the facility, if it's the substation they're allowed to do that. It's not available for transmission facilities because once they cross the road allowance, they invoke sort of the monopoly rights of the TFOs. But for the substations we do have that option.

Unfortunately, the primary service credit, in our view, and we've expressed this concern before this Commission in the past, does not anywhere near match what we think are the costs that we would incur. So we would love to build, own, and operate our own substations, if the primary service credit was designed properly. Then we would go away at least on that part of the problem.

But unfortunately, there's a major disincentive. We can't make it work economically when we should be able to, if that credit was -- puts you on a level playing field. So it shouldn't matter would owns the substation. It should be simply other factors. It shouldn't be a financial matter.

Q. Okay, sir. But the way the AESO tariff exists at this time, customers can own substation facilities, so there is an ownership component?
A. MR. LEVSON: You're technically correct, that is an option that is available that customers can build their own substation. And we would actually probably like to do that because then we can manage our costs better.

Q. Sure. Thank you, Mr. Levson.

Farther down on the first page of the opening statement, TCE indicates at point 3:

"Rider I payments would only be made by the customer causing the need for the contribution and, therefore, do not impact other ratepayers."

Also farther down that page at point 4, TCE indicates:

"Rider I would only be made available to creditworthy customers and, therefore, the risk of default is minimal. As Rider I would be an AESO tariff provision, the AESO would look to the customers in the unlikely event of default."

Now, gentlemen, in the context of these points on impact on other customers and default, could you turn up the response to ASBG/PGA TCE 012D, which is Exhibit 0111 in this proceeding.

Gentlemen, do you have that?

A. MR. LEVSON: Yes, we have it.

A. MR. KOSTESKY: Yes, we do.
Q. Thank you. Now, gentlemen, this response indicates number D, and I would just like to quote that response:

"Another option that was examined in the AltaLink working group was whether each TFO could finance the customer contributions in an arrangement between the customer and the TFO. This arrangement was rejected as it left the TFOs with default risk, although quite small, for which they would have to charge a large risk premium on the return component of the costs in the absence of a large pool of customers to manage that risk. If the costs of capital became too high, customers would opt to finance the customer contributions themselves, and the objective of restoring the TFO rate base would be lost."

Now, gentlemen, in reading that response, it appears to suggest that the TFOs considered an arrangement between a customer and a TFO where lump sum contributions at the outset of a project is substituted by amortized payments over 20 or more years is a significant risk that required a large risk premium. Could you agree with that paraphrasing, gentlemen?

A. MR. LEVSON: Yes. The TFOs -- there's two aspects to this. First of all, at a high level, and this is what I understand from what the TFOs said to us as we
were working on this, was that right now, under the normal assets that are already covered by the investment policy, they do not incur default risk. That's their understanding of it.

They assume that the AESO has the contracts with the customers and the TFOs have really nothing to do with the contracts, enforcing them, setting the tariffs or anything. So they assume that if a customer defaults, it's the AESO that has to go and recover whatever cost they can. The TFO will -- if it's eventually determined to be no longer used and useful, the facility would be retired. So that's sort of the starting point. So they looked at this as an increase in their risk that they didn't want to take on.

The reason for the larger risk premium is that -- part of the reason, anyways, as I understand it, is that, as we said, there's just -- at least initially, what might just be a handful of customers.

Default risk is managed down by having a large number of customers that you spread it over, and until that's in place, you have to assume the worst, unfortunately, that, you know, a customer might default and you have to build in this big risk premium.

But the opportunity we have as a system with 600 points of delivery, roughly, we can spread that risk
broadly. So they don't have that opportunity.

The other thing that -- of course, in our proposal, the way we manage that, of course, is with the creditworthiness test. So we take it over to the customers. We don't think it's a big risk because there have been virtually, to our knowledge, there's really no experience in Alberta of this actually happening at the TFO level. There's three customers that I have explored that might be a problem, but as I looked at them, more information I have on them, they were not imposing any burden on the system after the contractual management resolved and so on.

So I've been drifting a little bit, but the TFO on a stand-alone basis, with one or two or three customers starting us out, have to put in a bigger risk premium, but if we can do this across the whole system, it -- the risk which we think is small is spread even thinner. And then there's a bunch of measures to protect, and I can explore those with you if you'd like, beyond the creditworthiness test.

Would you like me to explore those with you?

Q. I think you've tried to address my question, and I think you're suggesting that to mitigate this risk, there has to be the large pool of customers, and with that large pool of customers, that is customers that have provided
customer contributions and also customers that have not
provided customer contributions. You would agree with
that, sir?

A. MR. LEVSON: Yes, we're basically saying
that it becomes an AESO matter to resolve, just like they
would on any customer that defaults today. They're going
to lose tariff revenues from it. It seems to happen
rarely, if at all. The perspective of 600, you know,
points of delivery, we're talking about one out of 600 that
never seem to ever happen anyways. And there are other
things that you can do. Like, you know, there's the
creditworthiness test which we think if the AESO applies it
rigorously, it would reduce the risk almost to zero.

Another thing to be aware of in Rider I,
we're not trying to get every customer on to Rider I. All
we're trying to do is make it available so that we can
shift some dollars over to the TFO and bring the amount
CIAC down to that sort of threshold of 10 percent. So if
we can get it down to 8 percent, that's probably going to
solve, our view at least, the TFO's concerns and yet we
don't need to expose ourselves to any risk.

Then if you go just a little bit beyond,
since you've given me the opportunity, if a customer
somehow gets through that creditworthiness test and still
is not able to back up their financial obligations, you
have to keep in mind that these are very large facilities. These are facilities that are typically hundreds of millions of dollars, if not a billion dollars - refineries, gas plants, those kind of facilities. And so if the company behind those facilities was to go bankrupt, then somebody's bound to pick up those assets and want to operate them, they're functional assets.

So in coming back from bankruptcy with a new owner and even setting them aside, that new owner would want to have power and the AESO simply says, pay your bills and you can have power.

The other thing is that these -- from the perspective of most customers, the amount of power that's consumed relative to the overall economics of the plant is actually quite a relatively small percentage.

So if the plant is viable, the electricity is not going to be an issue, they'll pay their bills, which is what the default concern is about.

There's more beyond, that too. Even if that didn't work -- even if you can't get a new owner to take on the obligations, then you can -- we should remember that this could happen anywhere in the life of the asset. The asset may have been depreciated already, there may be very little exposure of what's left on the books. And then, finally, even when the asset is retired, especially
1 substations, there's quite a bit of salvage value in things
2 like transformers and breakers, so a lot of times
3 transformers last much longer than the life of the contract
4 at 20 careers, so they can be used somewhere else.
5 Q. Thank you, Mr. Levson, for that elaboration.
6 But if I go back to my initial question, the
7 default risk to other customers -- and that other customers
8 are customers that do not have to provide a customer
9 contribution -- the impact on these other customers would
10 be minimized with the continuation of the status quo where
11 lump sum contributions are required from customers prior to
12 construction.
13 You would still agree with that observation;
14 would you not, sir?
15 A. MR. LEVSON: Yes. I mean, we're not
16 saying that Rider I has zero risk, to be clear. We think
17 it's very small. So if you're going to compare -- I think
18 to be fair, you need to compare not just people who have
19 made a contribution -- or have not made a contribution; you
20 need to include those who have made contributions because
21 we're going to have to bear it in that default risk as
22 well.
23 But probably more importantly is that our
24 proposal is largely here to compete with the management fee
25 as what we think is the better alternative.
And if this Commission decides to grant some form of management fee to AltaLink, and possibly to ATCO as well, then we've got a real cost, and we've got nothing else, you know, for it. We haven't got any more service, we haven't got any more reliability, we've got nothing for that extra cost.

So that management fee certainly got our attention, and that's what we're really competing with, not with status quo.

A. MR. KOSTESKY: Mr. Unryn, if I could just go back to your initial observation of point number 3 in the opening statement regarding the impact of other ratepayers. That point number 3 was structured so that it identified that the CIAC payments that have been made to the TFO Rider I would fall to that particular customer. So the intent of point number 3 was that Rider I was not to be spread over all of the AESO customers; it was going to track to the customer that triggered the contribution, and that was the point on not impacting other ratepayers from a collection of the Rider I payments. They would come from the customer that would have made the CIAC payments. And then we had a long discussion about the default risk as well.

I would echo Mr. Levson's comments that the Rider I, if it does follow, and we assume that it will
follow to the customer that is required to put up the contribution, then we're left with default risk, but if the management fee gets approved, that's paid by all customers and that's what we view is a much higher cost to the customers than the default risk that could be associated with Rider I.

Q. Okay, sir. You're assuming the management fee there would not be allocated, then, to specific customers?

You're suggesting it would be allocated over all of the AESO customers?

A. MR. KOSTESKY: That's an issue that needs to be resolved and it's best to be resolved in the AESO 2010 GTA when all the parties are present. We don't know which way it's going to go, but it is an additional cost that needs to be collected from customers, and I use that broadly because I'm not sure if that's isolated customers, or peanut butter I think is the word I've heard earlier on in the hearing. That is yet to be determined.

Q. Thank you, sir. Now, back to the opening statement. Point 5 indicates:

"Rider I would permit unamortized balances relating to legacy assets to be converted to Rider I."

Now, in the context of legacy assets, could you, again, turn up the response to ASBG/PGA TCE 12, which
is Exhibit 0111.

Now, I'd like to direct your attention to
the response to parts A to C.

A. MR. LEVSON: We have that.

Q. Now, in the response A to C, TCE provides a table and
at line 5, it indicates:

"That some 133.5 million dollars of unamortized
legacy assets could be converted to Rider I
payment options."

Do you see that, sir?

A. MR. LEVSON: Yes, I see that. Just to be
clear, that was the assumption we were asked to respond to.

So it's --

Q. So sort of the balance of unamortized legacy assets?

A. MR. LEVSON: That's right. We just didn't
worry about creditworthiness. We assumed that everybody
was creditworthy. If some aren't, then that number would
obviously go down.

Q. That's fine, sir. Now, in this respect, the TCE Rider
I proposal is similar to an additional capital cost project
proposal of $133 million that must be prioritized with all
other capital projects that AltaLink is proposing in this
proceeding.

Could you agree with that characterization,
gentlemen?
A. MR. KOSTESKY: Yes, we would.

Q. Thank you.

A. MR. LEVSON: With one caveat. If I might just add. When you said prioritized with, are you saying on an equal priority with --

Q. No, I --

A. MR. LEVSON: -- or just in the basket of things that --

Q. In the basket of capital projects.

A. MR. LEVSON: It's important to make that distinction because we have -- in our proposal, we are giving both the AESO and the TFO the complete control over whether these investments are made or not.

So if AltaLink was in a situation where they had capital constraints -- maybe I'm jumping ahead here. But if they were in the place of capital constraints, then they can just simply say no, if they think they can't get the capital.

This Rider I program is not designed to cause AltaLink any undue financial burden. That's why we put that provision into Rider I.

We had discussions with the TFOs about this very issue as a part of that work that we did in October and November of last year, and that's why that provision is in our proposal.
Q. Now, sir, are you suggesting, I guess, that legacy assets can be addressed, but you're suggesting that a financing concern can limit the amount of that conversion; and if, in fact, there is that limitation, how would you apply that, on a case-by-case basis, to particular customers and still have fairness in your proposal?

A. MR. LEVSON: Well, I guess that is case of, you know, a reasonable level of discrimination. First of all, we're saying customers who aren't creditworthy, they may apply, but they will not get approved by the AESO, before it even gets to the TFO.

If they make application for Rider I, the AESO determines them to be creditworthy, then the next step is you would then go to the TFO to make application. If it's a legacy asset, the TFO looks at that and says, We can afford this in our capital financing or we can't. And if they can't, they might say, Just put it on hold until we can.

So we're not -- you know, these are details that are best probably worked out in the AESO's 2010 GTA, but this is our flavour of it. Why we think we have a credible proposal is that the concerns that was expressed by the Commission we don't think need to be a concern, because the TFOs have control over this process for legacy assets.
I don't know if I have addressed your fully, the fairness issue. But I suppose if there's more customers seeking -- and I'm speculating here a little bit. But if there's, say, $50 million worth of contribution seeking to be treated under Rider I and the TFOs say they only got 30, then maybe they will do a draw or apportion it or something, but we'll find a way to make it fair among customers, I'm sure.

Q. A lottery or something.

A. MR. LEVSON: We're pretty good at making things fair.

Q. Okay, Mr. Levson, but you would agree that from what you put on the table, the $133 million, it certainly would -- would or could aggravate the cash flow situation for AltaLink, the credit metrics, and, you know, that could flow into financing costs which could impact all customers. Could you agree with that observation?

A. MR. LEVSON: Maybe Mr. Kostesky will weigh in on this, but I'm having difficulty agreeing with that, at least based on our review of Exhibit 226, which was filed by AltaLink.

We went through that quite carefully, and I could not find any flaw, really, in their calculations. I think that adding particularly legacy assets, because they immediately cash flow, and they actually improve AltaLink's
ability to raise capital, is the argument that they make, because of the coverage, the credit coverage that it helps. So it's different than a construction work in progress, a situation where you're raising the capital, but they don't have cash flow until it's commissioned and determined to be used and useful. So I was persuaded by it anyways.

Mr. Kostesky?

A. MR. KOSTESKY: Yes, I would echo those comments as well: that it appeared, based on Exhibit 226, that AltaLink came to the conclusion that converting legacy CIAC amounts to Rider I or financing them would be supportive, actually, of AltaLink's credit metrics, even during this big build era that they're coming into. I'm making reference to the very last paragraph before the table. The very first sentence indicates that.

Q. But, sir, Mr. Kostesky, certainly if AltaLink has to pay out an amount of 133 million or, I guess, even more, I think you suggested earlier, that the CIAC amount could be greater.

A. MR. KOSTESKY: Again, in Exhibit 226, they talk about how converting the CIAC is actually positive
because they -- the assets that they are converting are already generating cash flow, so it's actually positive, the way I read Exhibit 226.

Yes, they would have to go to the market to get the capital. If it's the full amount, we don't anticipate the full amount being converted to Rider I, but those assets are already generating cash flow.

The other thing that we've got to continue to bring up is that it is at the sole discretion of the TFO if they feel that they cannot provide the funding to convert CIAC amounts to a Rider I, they have the option to say, No, we can't do it at this time.

A. MR. LEVSON: Mr. Unryn, you said something that I didn't quite understand. I thought we had said the opposite. You said that it could be 133.5 million or more. Did you mean to say "less"?

Q. No, I was just following up on Mr. Kostesky's earlier comments that the CIAC amount could go up into the $200 million mark, so -- very shortly.

A. MR. KOSTESKY: And I referred that -- or that number came from table 1 of AltaLink's rebuttal evidence on page 52. Their number projected for 2010 is 229.5 million of CIAC. So that's where that number came from.

Q. So the 133 million, then, can actually increase rather
than decrease. I think that's your point; is it, Mr. Levson?

A. MR. LEVSON: Maybe we're talking about apples and oranges here. I think this -- this 133.5 is legacy assets. I thought that was the context that we were talking about. So, yes, if you're referring to -- this is the most that the legacy assets can be, as far as we know from the books of AltaLink, from their numbers.

I suggest it could be any number between there and zero, at their discretion. But for the new contributions that are coming on and the new facilities that are coming on the system and the associated contributions, those amounts would also need to be potentially financed after, in our view -- and that's the change that we made to the evidence -- that would happen after -- to be clear, after they are used and useful, not prior to -- not during the construction phase.

Q. Right, yes, I think that change you made -- so there would be the initial contribution before construction starts, and then there would be a refund of that contribution after construction is completed and it's in service.

A. MR. LEVSON: There could be a refund if they're creditworthy, right, but not -- only under that condition.
Q. Thank you. Gentlemen, I have a few questions for clarification with respect to your response to ASBG/PGA TCE 001, which is Exhibit 0111 in this proceeding.

A. MR. KOSTESKY: We've got it.

Q. Okay, thank you.

Now, in response to 1 C, TCE indicates that new STS customers may be required to pay an upfront system contribution, but this contribution would not be subject to the proposed AESO Rider I.

Could you agree with my paraphrasing of that response, sir?

A. MR. LEVSON: I didn't see that in the response. Can you repeat your paraphrasing, please?

Q. Okay, new STS customers may be required to pay an upfront system contribution, but this contribution would subject to the proposed AESO Rider I.

So we're looking at system contributions versus contributions for interconnection?

A. MR. LEVSON: Yes, that's -- there's a provision in the AESO tariff, nothing to do with a normal interconnection, to do with the -- when you're moving -- building generation in a generation-rich area and sending that electricity to a load area, there's a provision to charge contribution for supporting the bulk system costs.

It's not a really large number, and it's
also refunded. So we had wanted to be clear we're not proposing that any of those contributions should be a part of the Rider I program.

Q. Okay, sir.

A. MR. LEVSON: They would be left as they are. When I say -- they are refunded over time, under certain conditions. The generator has to produce certain levels of electricity every year to qualify for a refund.

Q. Yes, that's my understanding: that the AESO is required to repay the STS system contribution to the STS customer over a period of nine years if the generator meets specified performance criteria. That's what you're referring to, sir?

A. MR. LEVSON: You said it more eloquently than I did, yes.

Q. Thank you. Now, in contrast to the system contribution requirement, the STS customer could spread out the interconnection costs, the payments associated with those interconnection costs, over a period of 20 years, pursuant to your proposed Rider I. Is my understanding correct, sir?

A. MR. LEVSON: We set a range of between 10 and 20 years for STS-type customers.

Q. Right.

A. MR. LEVSON: But not in excess of 20.
1 Q. Right. Up to 20 years?
2 A. MR. LEVSON: Yes, but not below 10.
3 Q. For consistency purposes, why wouldn't you have
4 utilized amortization periods and performance criteria for
5 the STS interconnection customer contribution in the same
6 manner?
7 A. MR. LEVSON: Well, we were endeavouring to
8 balance interests, to come up with a viable proposal. And
9 some generators, because of the nature of the generation,
10 it may be more appropriate for them to have a shorter
11 amortization period, by their own choice or perhaps the
12 choice of the AESO.
13 We didn't go below ten years, because if we
14 go too short, then the TFOs say that their problem isn't
15 being addressed, which is they would like to have this in
16 their rate base. So if they have got a generating asset
17 that lasts 30 years and they only get return on enough
18 capital for ten years or less than ten years, then they
19 consider that a problem.
20 So, again, we are just trying to demonstrate
21 that this would be in the range of what would work for
22 STS-type customers, and it is a detail that we can refine
23 as we get into the AESO's '010 GTA.
24 Q. Okay, sir, thank you.
25 A. Gentlemen, could you turn now to your
response to ASBG/PGA TCE 008, which is the same Exhibit 0111.

A. MR. KOSTESKY: We have that.

Q. Okay, sir, in response to part A, TCE indicates that any benefits of the Rider I proposal must be compared to the management fee proposal and not to the status quo. I believe we've discussed part of that earlier. But should I read into that response that there are no benefits of the Rider I proposal to other ratepayers relative to the status quo?

A. MR. LEVSON: So at least from my perspective, having been in the industry a long time, I think there are advantages to having a Rider I option in any jurisdiction. It has been in place at TransAlta for a number of years.

Mr. Wayne Taylor, who was the rate designer, is one of the people I spoke to about this. Unfortunately, it's not very explicit in the terms and conditions, so I can't point you to a specific rider -- a detail in a rider from one of TransAlta's previous decisions, but it was a business practice. So a customer could come and have their contribution amortized over time.

I understand that ATCO has had a similar one -- situation.

We filed -- we, so much as Keystone -- filed
V. KOSTESKY, D. LEVSON  
- Cross-Examined by Mr. Unryn

1 evidence in the ATCO proceeding on the same matter and drew
2 the Commission's attention to some cases in the States
3 where this has been made available to the Keystone
4 pipeline.

      It just makes sense that for some customers,
5 that for whatever reason, that they would like to take
6 their contributions and have them spread over time. That's
7 how they get the benefit. They get the benefit over time.
8 So it makes sense to spread the costs over time.
9
10      So, yes, to answer your question, I think,
11 yes, with that explanation, I think there would be a
12 benefit of Rider I compared to status quo.
13 Q. That would be for specific customers?
14 A. MR. LEVSON: For specific customers. And
15 the same kinds of things would apply: You'd have to do
16 your creditworthy test and so on.
17
18      So it's been done in the past; it's done
19 elsewhere; and we think it makes sense here.
20 Q. Okay. Sir, in terms of an STS customer chooses a site
21 for development, would you agree that the requirement for a
22 full, upfront contribution for interconnection facilities
23 causes more discipline in the sighting decision, rather
24 than having a series of annual payments for 20 years?
25 A. MR. LEVSON: I guess, at the highest
26 level, any time you ask somebody to pay, say, $5 million
today versus spreading it over time, there is an additional
financial obligation that you're imposing on that -- on
that player.

But for larger customers, whether they're a
dFO or whether they're a large industrial customer or a
reasonably sized generator, I don't think they are affected
materially by that kind of discipline, because financially
they're equivalent, whether it's -- roughly equivalent,
whether it's spread over time -- you know, you're going to
pay your return on and return of. And so they're -- you're
pretty much indifferent.

I think where discipline comes in is where
you actually have a cost that's imposed on you, that's
higher than another location. So if you're a generator and
you pay higher losses at one location or another, then that
incents you to do something different.

It's not actually necessarily an upfront
payment, obviously, but that's the kind of thing that
causes us to think about what we're doing and where we're
doing it.

From a generator perspective, from a load
perspective, my experience over the years is that most
loads -- we're talking TFO loads now, or AESO loads, not
distribution level loads.

People are building the plant around a lot
more important things than the cost of electricity. It's just -- it's a cost of doing business, but it's -- they're not going to not build a oil sands plant because of any kind of signal that we can come up with here. It may not be a fair price, but it's not going to materially affect their decisions, from my experience.

A. MR. KOSTESKY: I'd like to just add to that, Mr. Unryn, that the intended signal that the contribution for interconnection facilities was intended to provide -- it's still preserved. That interconnection payment that's required above the investment level will still apply. And what we're talking about is whether it comes in the form of a CIAC payment or it comes in the form of an amortized payment stream over a Rider I-type concept.

So I agree with you that the intent of that contribution was to signal the generators to try to locate as close as possible to the bulk system. So I would agree that statement.

But that's different than signals coming from Rider I versus a CIAC. I think that they're exactly the same. The difference between CIAC and Rider I doesn't affect the signal. The signal is still there. It's how is it paid for.

Q. Gentlemen, does the 12 percent prepaid O&M charge remain as part of the TCE Rider I proposal in this
proceeding?

A. MR. LEVSON: The Rider I is basically a proposal that deals with what has been determined to be CIAC. How that amount is determined is, I think, a separate issue that we really haven't addressed, other than in one way.

We acknowledge that if this Commission agrees with the parties that were advancing the review and variance application, which, as I understand, is unanimous for the amounts below the maximum investment level, that if the Commission does agree with that and makes that revision to the tariff, the impact of that will be that there will be a reduction in the total amount of cost that goes in before the investment policy is applied.

Do you want me to give you a quick example, or is that sufficient?

Q. I think so. So your proposal is in line with the R&V before this Board; is that . . .

A. MR. LEVSON: Yes, it's in line with it. They're not -- they're independent. They largely -- the only other thing we've observed is that if the Commission does agree with the proposal in the review and variance, that it will take a little bit of pressure off of CIAC as well, among some other factors, and reasons why we -- it gets to the issue of how urgent is this matter, so . . .
Q. Okay, sir. In the AESO terms and conditions, article 9-14 provides the details of the discount rate applicable to payments pursuant to article 9.

Now, in contrast to this existing discount rate, the TCE proposal references the TFO weighted cost of capital for payments.

What was the reason for the change in respect of the discount rate?

A. MR. LEVSON: The reason is fairly straightforward and that's that the CIAC assets will be on the books of the TFO, not the AESO. So in order to match the cost that the TFO incurs with the payments that would be made under Rider I, we felt it was appropriate that the weighted average cost of capital of the TFO that has that CIAC on the books, would be the appropriate one.

There was some discussion, you know, about having a province-wide, you know, weighted average cost of capital, but that, very quickly, is dismissed. It's just not practical. And it leaves a problem with a generic one versus the individual TFOs because what are you going to do with the difference? Who's going to make that up? So the obvious thing to do is to just give the weighted average cost of capital of that particular TFO and apply it to that particular customer's arrangement. And it's totally acceptable to those of the customers that were involved at
least. It didn't seem to be an issue at all. It just seemed logical.

Q. So that calculation would be specific to the customers of each TFO?

A. MR. LEVSON: That's correct. So if we had a CIAC amount in the AltaLink service territory, then we would have the AltaLink weighted average cost of capital and ATCO would be -- their weighted average cost of capital would apply. It keeps everything consistent.

Q. You don't think that, administratively, we're going down the road of more and more complexity?

A. MR. LEVSON: Yes, there's -- we've answered some of your questions around complexity. I'd agree with you, this would be difficult you know when you get down to residential customers, it would be a challenge, but given the multi-million dollar type levels of contributions, the relatively small number of them, we don't think it's a problem.

The AESO has been a part of our discussions and deliberations on this and they did not raise this as a concern. I can tell you from experience that if the AESO has a concern with administration, they usually let us know pretty quick.

Q. Thank you, sir.

In your response to ASBG/PGA TCE 10, and I
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-Cross-Examined by Mr. Unryn

don't think you actually have to pull it up, it addresses regulatory efficiencies.

Currently the AUC is conducting a generic cost of capital proceeding for all the utilities in the province.

Does TCE consider that such proceeding will address the capital structure of utilities and, therefore, will also consider the impact of CIAC on capital structures?

A. MR. LEVSON: That was a good question.

Obviously there's lots of evidence on the record in this proceeding from AltaLink that these matters aren't the rate of return that they deserve, are entitled to and CIAC are related, but I don't think we really can answer -- give you much help on that question. If parties in this proceeding want to raise it, then it's up to them, but it's not been in our thinking.

Our proposal does not depend on going into a generic cost of capital proceeding and getting into a big debate on all the inefficiencies involved in that matter and trying to figure out what adjustments to return should happen for various utilities based on how much CIAC they have. We're trying to come at it more in a fundamental level and say let's just find ways to lower the level of CIAC below that 10 percent threshold and solve some of our
concerns, the customer concerns at the same time. I think it's a better way to go.

I have to tell you, Mr. Unryn, I am not a cost of capital expert, but I have been around the industry long enough to know that those proceedings tend to be quite complex, and this would be just another thing. I don't know how you could separate them out. It would be quite a challenge.

A. MR. KOSTESKY: If I could just add to that, Mr. Unryn. I'm kind of glad that I did turn response 10 up.

In the context of our response there, the regulatory efficiencies we were talking about is dealing with either a management fee or Rider I in one forum rather than dealing with it in multiple forums, and we've had this management fee discussion in the ATCO proceeding as well.

So the efficiency we're talking about is let's deal with it in one forum, which is primarily the AESO 2010 GTA, to assess its merits, rather than going it piecemeal through every TFO's application. I think that's the context of the response in 10.

Q. Okay, sir. The piecemeal, it may be solved to a certain extent if it was addressed in a generic cost of capital. Would you agree with that, sir?

A. MR. KOSTESKY: Possibly.
Q. Okay, thank you.

MR. UNRYN: Thank you, Mr. Kostesky, Mr. Levson. Those are all my questions.

Mr. Chairman, members of the Commission, thank you for the opportunity.

THE CHAIR: Thank you, Mr. Unryn.

MR. ROSS: Good morning, Mr. Chairman. I am certainly prepared to proceed right now. I see on the clock it's 20 after 10. So I'm in your hands as to whether you want to take a break now or whether you'd like me to proceed.

I will most certainly go in my examination after the proposed 10:30 break, so I'm prepared to start and stop or take our break now.

THE CHAIR: Mr. Ross, we do have an interesting clocks. I'm looking at quarter after on the back clock, so I'm using that one, so I'm thinking 15 minutes in would probably be beneficial. That would give all of us an opportunity to hear some of the things you're asking about and then continue after the break.

MR. ROSS: Certainly, sir.

Good morning, panelists. Good morning, Mr. Kostesky and Mr. Levson.
MR. ROSS CROSS-EXAMINES THE PANEL:

Q. I want to refer you and explore with you in the first instance an amendment that we've heard this morning in respect of page 4, lines 9 and 10 of your March 6, 2009 evidence. I will give you a moment to turn that up.

For the record, that's Exhibit 0094.00 TCE LTD-102. If you have that, from what I have heard this morning, you're looking to make an amendment which takes out the wording "customers would have an option to pay customer contribution or could apply for a Rider I repayment of the customer contribution at the time of interconnection." Correct me if I'm wrong, but you're removing the reference to having an option and changing "or" to "and." Is that correct?

A. MR. KOSTESKY: Just one extra word that we're deleting, the word "to," so having the option to is deleted, so the word "to" is also deleted.

Q. But Mr. Kostesky, you're still providing essentially two types of payment option notwithstanding this change; is that correct?

A. MR. KOSTESKY: Yes, there's either a CIAC or a Rider I repayment, yes.

Q. Thank you, sir, for that clarification.

Just another matter of clarification and as a matter of terminology, can we agree that the AESO
customer contribution policy, which is often referred in
these proceedings as the AESO investment policy, is set out
at article 9 of the AESO terms and conditions of the AESO
2007 tariff; correct?
A. MR. KOSTESKY: Subject to check, correct.
Q. For the purposes of the record, Mr. Chairman, that's
found at Exhibit 0111.00 TCE LTD 102.
Mr. Kostesky, can we agree that under Rider
I, as proposed by TCE, the choice to pay the customer
contribution is equivalent to the customer prepaying the
full amount of the customer-related facilities not covered
by the AESO investment policy?
A. MR. KOSTESKY: Can you give me that question
again?
Q. Certainly. Under your Rider I proposal, we've agreed
already that there are two options here in play: One is a
customer contribution and one is a repayment of customer
contribution at the time of interconnection.
So the first being option 1, that payment of
customer contribution, we could characterize that as a
prepayment of the full amount of the customer-related
facilities; correct?
A. MR. KOSTESKY: That's correct. I just want
to draw a distinction in our proposal in dealing with
legacy assets versus new assets. So I'm assuming you're
talking about the new assets because the legacy assets, the payments have already been made.

Q. That's correct, sir, and we'll get to legacy assets later on. So I take your answer.

Can we further agree that, and I'm quoting, "applying for a Rider I repayment of a customer contribution at the time of interconnection" would involve signing a facility or a tariff contract? That's part of your Rider I proposal?

A. MR. LEVSON: Yes, these arrangements will be done under contract.

Q. Mr. Levson, that contract would essentially provide the transmission facilities operator -- for the record, TFO -- with a return of its investment, plus a return on any amortized balances calculated based on the TFO's weighted average cost of capital for customer-specific facilities; yes?

A. MR. LEVSON: Yes. I think you said "unamortized"; is that right?

Q. That's correct. Can we further agree that under Rider -- under your rider repayment of the customer contribution at the time of interconnection is essentially a deferred payment?

A. MR. KOSTESKY: I don't know how you would want to define deferred payment. I would certainly say
it's an amortized payment. Is it deferred? It all depends on how you define deferred, but it certainly is an amortized payment.

Q. Okay. Further, that the contribution at the time of interconnection could be characterized as an amortized payment or perhaps deferred payment with a carrying charges option.

A. MR. KOSTESKY: Can you explain to me what you mean by a carrying charge option?

Q. Well, I guess -- I mean I'm certainly a simple lawyer but why don't we take it this way: If we were to view at a broad level that carrying charges involved interest charged, for example, on a balance owed when paying in installments, that that might be a type of carrying charge to consider.

A. MR. LEVSON: I guess maybe in a broad sense that might be in the ballpark. A simpler way of expressing it I think is it's just the traditional cost of service calculation involved in the cost of capital for these facilities. So it includes a return on and return of the capital over time.

It basically matches pretty much what happens with all the other TFO assets, same way that average cost of capital -- everything is the same. The only difference is instead of it being a lump sum number
that goes to the TFO, it gets kind of labelled as
associated with a particular customer and goes through
Rider I for cost recovery through payments from that
customer. So that's -- nothing more complicated than that,
I think.

Q. Thank you, sir. Can we agree that repayment of the
customer contribution at the time of interconnection under
Rider I constitutes compensation for services rendered?

A. MR. KOSTESKY: Depending what services
you're talking about, but under Rider I, they would be
earning the same return as they would for investment policy
investments, if I might use those acronyms.

The calculation for the amount of payment
that falls out of that calculation is the same calculation
as would be for the rest of the TFOs' investment. So it
would include a return on and a return of capital.

So I don't see those being any different.

The calculations and the amounts that come out of those
calculations for Rider I are the same calculations that are
done for the TFO revenue requirement for their rate base?

A. MR. LEVSON: Mr. Ross, can you elaborate a
little bit when you said services? That's what kind of
caught my attention. I don't normally consider these --
this kind of a transaction to be a service. Like when I
say services, I'm thinking operations and maintenance or
something like that.

Q. Well, with respect to the question of services, I guess what I had in mind in a general sense is certainly some of the -- let's take, for an example, maintenance-related issues. Let's take, for an example, ensuring reliability. Would you include those in your assessment?

A. MR. LEVSON: All of the services that are outside of the capital part, as we understand it, are recovered through the revenue requirement of the TFO.

So operations and maintenance costs are not -- this is the prepaid ones, but assuming that they aren't there, they are normally recovered through the TFOs' revenue requirement. They're not a part of this.

We're not asking for the Rider I to include -- to be more clear, we're not asking it to include anything other than a financial transaction around the payment of the CIAC amount.

Q. Thank you, sir. Can we agree that under Rider I, compensation, when contributed at the time of interconnection, is through a return on equity?

A. MR. LEVSON: Return on equity is a part of compensation.

Q. In that vein, Mr. Levson, can we agree that repayment of the customer contribution at the time of interconnection
in respect of Rider I would include an obligation to repay principal through amortization of original cost over time?

A. MR. LEVSON: That's correct, as well as debt. So those would be the three components. The fourth one, of course, that attracts the equity is the income taxes.

Q. You've moved me ahead to my next question, sir, but I will ask it nonetheless. Can we agree that repayment of customer contribution at the time of interconnection under your Rider I includes the repayment of the interest component on the debt of TFO's financing?

A. MR. LEVSON: Yes.

Q. Can we agree that under Rider I, if a customer chooses to pay the customer contribution as a prepayment, which you've agreed to, Mr. Levson and Mr. Kostesky, that the TFO does not receive any income stream attached to that prepayment amount?

A. MR. KOSTESKY: So for new facilities, they would not receive a cash flow from the asset while it's under construction. They would begin to receive cash flow once it was in service, used and useful. So during that time period when the CIAC payment was made and the time that it was -- that the facility was built and interconnected and used and useful, yes, during that time period, the TFO would not have any cash flow from that
project, but they would have the CIAC payment on account as well.

Q. Thank you, sir. Can we agree that a TFO's responsibilities and risks associated with assets that it acquires under either a prepayment or a deferred payment, as we've discussed this morning, are the same?

A. MR. LEVSON: I don't think a prepayment, a lump sum prepayment of the entire CIAC and a payment over time involve the same risk.

If that was the case, I don't think we would have had the discussion with Mr. Unryn about default risk. So they are close if the default risk is minimal, but they're not exactly the same.

Q. Thank you, sir. Mr. Kostesky, I want to get you back to a discussion we had a few minutes ago and I just want to try and summarize. Can we agree that under what's been referred to as prepayment or prepayment option under Rider I, AltaLink would receive no income for -- and we've talked in a broad sense of services, but let's revisit that, for services it provides using the assets financed under the prepayment option? Correct? I think we've agreed to that.

A. MR. KOSTESKY: Yes.

Q. But that it would receive income for the same services if assets are financed under a deferred payment option; correct?
A. MR. KOSTESKY: The only difference between those two time elements is that assets are being constructed.

Q. But I want to take you -- I think we've agreed to the first part of that question with respect to income for services provided using assets financed under a prepayment, but would it receive income for the same services if the assets are financed under what I'm referring to as deferred payment, you referred to as amortized?

A. MR. KOSTESKY: So the very first part, they're not receiving any income from the asset while it's under construction. So I'm not sure when you recharacterize the first part of your question as to whether the TFO is receiving income for the services it's providing when there's a prepayment option.

I distinguish the two as a prepayment while the asset is being constructed, so there is no income from that asset while it's being constructed.

They do have the CIAC payment, but they don't have an income stream for that asset because it's not in service.

Does that help clarify?

Q. Yes, it does, sir. Thank you.

Mr. Levson and Mr. Kostesky, you're familiar with AltaLink's proposed management fee including evidence...
given in this proceeding by Dr. Charles Cicchetti; correct?
A. MR. KOSTESKY: Yes.
Q. Can we agree that through its proposed management fee, AltaLink is seeking only a share of the return for the portion of CIAC that it would finance with equity and not with new debt; correct?
A. MR. KOSTESKY: So the way I understand that is the calculation in determining what the management fee is, is on what the return of equity would have been had they invested in it. There is no actual equity infusion by the TFO. It's a calculation based on what would have been the equity component. So I think that's the background of the management fee calculation, as I see it.
Q. Well, just so the record is clear, I want to take you back to Dr. Cicchetti's evidence in-chief, which is Exhibit 2 to the AltaLink application. I will give you a moment to turn that up. But in particular, if you could please turn to page 31 of Dr. Cicchetti's evidence, lines 13 and 14.
A. MR. KOSTESKY: Can you give us those references again, Mr. Ross?
Q. Certainly. It's AltaLink's application. It's Dr. Cicchetti's evidence in-chief, Exhibit 2 of the whole application, Exhibit 2 to this record, and it's page 31, lines 13 and 14.
A. It's only a brief statement. I can read the
language into the record, if it's helpful.

A. MR. KOSTESKY: We have it.

Q. It says for the record, and I quote:

"AltaLink seeks the more conservative equity only share of the return on for the portion of CIAC it would expect to finance with equity, not new debt."

I will let you take a look at it, but on the basis of that, can we agree that through its proposed management fee, AltaLink is seeking only a share of the return for the portion of the CIAC it would finance with equity and not new debt; yes?

A. MR. LEVSON: No, I don't think we can agree. Because the key word there is "expect," and we have no indication that AltaLink is going to invest in these assets. We, the customer, invested in these assets. We incurred the return on equity. We had to pay for that cost. We had to pay the cost of debt. We had to pay the income taxes, not the TFO.

So he's got a calculation in here that's something like the lost opportunity if they could have invested, but they didn't.

Q. Well, sir, I take your view.

But just for the purposes of agreeing on what AltaLink's position is, can we, at least degree in
principle, that AltaLink is seeking only share of the return of the CIAC it would finance with equity, simply on the basic reading of those --

A. MR. LEVSON: Yes, AltaLink is, in my characterization of it -- is -- taken a tradition cost of service calculation for the capital portion and has extracted out the equity piece.

For clarity, they have also, in my review of the application, added the income tax effect, which we'll also have to pay for, as if they had invested, but they did not.

Q. But it's a portion of equity, not new debt; correct?

A. MR. LEVSON: It includes -- they removed the debt portion. I agree that that's how the calculation works. But where I take issue is there was no investment.

Q. I will move it along. But let me, then, in that case, give you a hypothetical.

Assume with me an AltaLink equity thickness of 38 percent; yes?

A. MR. KOSTESKY: Okay.

Q. Under that scenario, a management fee as proposed by AltaLink would involve a customer paying a return on just 38 percent of equity; correct?

A. MR. LEVSON: That's correct. You'd pay the 38 percent return on equity, and then you would gross
it up for income taxes.

Q. Let's put income taxes aside for a minute. So you go in there with a 38 percent of equity; correct?

A. MR. LEVSON: For your example, let's go with that.

Q. For the example. And then I want to go to your example: Rider I. And under Rider I, the customer would repay the full amount of the customer-specific facility, plus a return on the full amount; correct?

A. MR. KOSTESKY: That's correct, but there's a fairly significant difference. And that, to me, is that under the CIAC scenario, the customer has put up the cash for the assets under Rider I; the TFO has put up the cash in the form of equity and debt. So the Rider I scenario is -- tracks the investment, from the TFO perspective, from financing.

Q. But I just want to get -- I hear your opinion, sir, but I just want to get back to the fundamental principles of Rider I, and that is that the customer would repay the full amount of the customer-specific facility, plus a return on the full amount; correct?

A. MR. KOSTESKY: Yes.

Q. Therefore -- we've discussed AltaLink's 38 percent equity, we've discussed what you've agreed to under
Rider I. Therefore, with that in mind, can we agree that a
customer would pay less if it prepaid the CIAC and paid the
AltaLink proposed management fee, than it would pay under
Rider I?
A. MR. KOSTESKY: I don't think I can agree
with that statement. We've done some analysis in taking
kind of three scenarios. We've done what the cost is or
what the cash flows are from the customer for providing a
CIAC payment. That's number 1.

Number 2, we took that same scenario and
added a management fee calculation or a management fee
component to that calculation.

And then number 3, we've taken the Rider I,
and we compared the three. And we found that the CIAC,
with a management fee adder to it -- the amount that the
customer actually would see is quite a bit higher than
either a CIAC prepayment or a Rider I.

Q. Mr. Kostesky, has that background scenario ever filed
on the record in this proceeding?
A. MR. KOSTESKY: No, they have not.

Q. Thank you, sir. Sir, I don't want to, at this point,
deal with matters which haven't been entered as evidence in
this proceeding. I simply --
A. MR. KOSTESKY: We'd be more than glad to
submit our calculations and our findings on that, on those
cases that we -- I just explained.

Q. That's fine, sir. I'm not seeking an undertaking. I just want to get back to fundamental principals that you've agreed to.

We've talked about a 38 percent equity thickness. We've also talked about, as you've agreed to, Mr. Kostesky, that under Rider I, a customer would repay the full amount of the customer-specific facility, plus a return on the full amount.

And my question to you in that context is, extraneous evidence aside, is that it may well be -- would you agree with me -- it may be that a customer would pay less if it prepaid the CIAC and paid the AltaLink proposed management fee, than it would pay under Rider I?

A. MR. LEVSON: No, we can agree with that. Because under the management fee proposal, we still -- as a customer, from a customer perspective -- we still have to finance the asset. We incur costs very similar to the TFO's costs.

So if you take an example of -- whatever -- $5 million contribution, under status quo, we have to go out and finance that and pay for that over time. That's part of our tariff. That's an amount we pay.

Under the management fee proposal, we pay that amount again; we still pay that amount; plus we pay
the management fee. Under the Rider I proposal, we let the
TFO make the investment that we would have made, and we pay
the TFO over time, and we don't have to pay a management
fee.

Our analysis says that by -- you can pick
any kind of debt equity, within reason, that you can think
of. You're always going to be, on an NPV basis, roughly,
in our calculations, 37 percent more expensive under the
management fee proposal.

A. MR. KOSTESKY: So if I could just add to
that, Mr. Ross.

When you compare just the management fee to
the Rider I payments, you're right: It would be less. But
that's not the full picture. The full picture is the CIAC
payment and the management fee, compared to Rider I.

And I think that's the erroneous comparison
that's done when you just compare management fee to
Rider I. You're missing the CIAC component as well.

MR. ROSS: Mr. Chairman, I'm sensitive
to the time.

Q. MR. ROSS: I just have one follow-up
question to that, Mr. Kostesky, in this area; and then
propose to move on to other areas of questioning.

I just want to be clear for the record,
Mr. Kostesky, that it may well be that under Rider I, the
customer repayment of the full amount of a
customer-specific facility, plus a return on the full
amount, may be greater than a customer paying a return on
just 38 percent of equity. Leave aside our other
discussion. Would you agree with that statement?
A. MR. LEVSON: That's straight arithmetic,
Mr. Ross, but that's not -- just to be absolutely clear,
that is not what the customer has to pay. The customer has
to pay the CIAC on top of the management fee.
So, yes, arithmetic would suggest that if
you take the equity component only out of the calculation,
that it is less expensive. That is not what we pay.
MR. ROSS: Thank you, Mr. Chairman. I
do have further questioning, but I'm in your hands. I
would propose to break at this time.
THE CHAIR: Thank you, Mr. Ross. Let's
have a 15-minute break. Back at 5 to, on the clock at the
back.
MR. ROSS: Thank you, sir.
(ADJOURNMENT)
THE CHAIR: Mr. Ross, whenever you're
ready. I am seeing an influx of paper. Are we going to
address some of that?
MR. ROSS: That's correct, sir. There's
an initial couple of housekeeping matters. I have got a
whole suite of undertaking responses from AltaLink that I
would like to go through.

I also note, as well, that Mr. Forster has
approached me and he has a procedural matter he wishes to
raise at this time as well, but I propose we go through the
undertakings first, if that suits you, sir.

The first undertaking, and I apologize if
there's a mixture of paper, pertains to Volume 7, page 1020
and it's an undertaking to explain how a ratio of 1.4 was
arrived at when comparing a 29 percent increase in forecast
midyear rate base to a 16 percent increase in operating
FTEs. My understanding is, sir, is we're up to Exhibit
256, I believe.

THE CHAIR: 257.

MR. ROSS: 257.

EXHIBIT 257 - RESPONSE TO UNDERTAKING GIVEN AT
TRANSCRIPT VOLUME 7, PAGE 1020.

MR. ROSS: The next undertaking
pertains to transcript reference Volume 7, page 1071. It's
an undertaking to provide a copy of what the new
direct-assign letter looks like.

That would be exhibit number 258, I believe.

THE CHAIR: Number 258, Mr. Ross.

EXHIBIT 258 - RESPONSE TO UNDERTAKING GIVEN AT
TRANSCRIPT VOLUME 7, PAGE 1071.
MR. ROSS: The next undertaking pertains to Volume 7 at page 1066. It's an undertaking to provide the letter from the AESO that gave AltaLink the backstop for the expenditures up to the 35 million.

THE CHAIR: Number 259.

EXHIBIT 259 - RESPONSE TO UNDERTAKING GIVEN AT TRANSCRIPT VOLUME 7, PAGE 1066.

MR. ROSS: Thank you, sir. The next undertaking relates to transcript reference Volume 7, page 1059. It's an undertaking to advise of the number of 5.7 million changes in relation to the opening balance January 1, 2009 forecast.

THE CHAIR: Number 260.

EXHIBIT 260 - RESPONSE TO UNDERTAKING GIVEN AT TRANSCRIPT VOLUME 7, PAGE 1059.

MR. ROSS: The next, sir, pertains to Volume 7, page 985. It's an undertaking to provide the computation of salaries that exceed the CCA max in order to understand how the DC pension cost was derived.

THE CHAIR: Number 261, Mr. Ross.

EXHIBIT 261 - RESPONSE TO UNDERTAKING GIVEN AT TRANSCRIPT VOLUME 7, PAGE 985.

MR. ROSS: Thank you, sir. The final one at this time pertains to Volume 7, page 987. It's an undertaking to provide a recast of the cost shown in most
recent confirmed rates.

THE CHAIR: Number 262, Mr. Ross.

EXHIBIT 262 - RESPONSE TO UNDERTAKING GIVEN AT TRANSCRIPT VOLUME 7, PAGE 987.

MR. ROSS: Thank you very much, sir.

THE CHAIR: Mr. Forster.

MR. FORSTER: Thank you, Mr. Chairman. I do have an undertaking to file, sir, and some procedural matters to address, but before doing so, sir, I'd like to comment or follow up on some comment I made last night.

It appears that my comments last evening regarding Mr. Williamson's cross and the use of the Commission's IR process were unclear.

My only point was this: The Board, your predecessor, often admonished parties to ensure they fully utilized the Board's discovery or IR process, and I assumed that the Commission takes the same view. There is often obviously a question whether a party has fully utilized the Commission's IR process; however, here it is clear the applicant has not done so as it failed to ask any questions at all of IPCAAA and the UCA through the IR process.

Having said that, if my comments last evening were misinterpreted, and if they could be construed as suggesting that Mr. Williamson acted improper in any way, that was not my intention and I apologize to
Mr. Williamson and to the Commission for not being clear in that respect.

Sir, I have one undertaking response at this time. It is an undertaking by Ms. Holgate to produce the schedule from section 3.6 of the deferral account hearing. It is entitled "AltaLink application for reconciliation of deferral accounts 2004-2006 capital deferral account project summary by cost components. Projects initiated in 2004 to 2005." If that could be the next exhibit, please.

THE CHAIR: That would be exhibit number 263.

EXHIBIT 263 - RESPONSE TO UNDERTAKING BY MS. HOLGATE TO PRODUCE THE SCHEDULE FROM SECTION 3.6 OF THE DEFERRAL ACCOUNT HEARING.

MR. FORSTER: Two additional matters and these are the procedural matters, Mr. Chairman.

There were a number of questions asked yesterday by Mr. Williamson of Mr. Mohr concerning an attachment to IPCAA -- excuse me, AUC IPCAA UCA 11 B. Mr. Mohr had referred to a document prepared by Keystone in the TransAlta -- in the ATCO proceeding in his evidence and the Commission had requested that that be provided. It was provided and he was asked a number of questions on that.

I simply want to highlight for the Commission's information and other parties' information in
this proceeding that the actual author, the notorious
author of that particular piece of evidence is now sitting
as a witness in this proceeding, and if there are any
questions any other party or the applicant or the
Commission may have with respect to that document,
Mr. Levson, I think, is fully qualified to speak to that.

My final matter today, sir, has to do with a
confusion on the record which I noted and attempted to
correct in redirect last evening. The confusion arose out
of a question asked by the Commission. The question asked
was of Ms. Holgate and requested her opinion on the value
of a transactional net margin method to calculating a fair
market value. Her opinion on this matter is actually
contained in her opening statement, but given the opening
statement, even given the opening statement, the confusion
raised on the record last evening, I think, leaves the
record unclear.

If the witness -- it's my position, sir, if
the witnesses were still on the stand today, you would be
hearing -- what you would be hearing would be transcript
correction or testimony correction from the witnesses. The
fact is that they have been excused, and what we propose to
do is to file a transcript correction, but I wanted to
indicate that it would be more of a substantive nature than
what one would normally see. And it is to ensure that the
opinion provided by Ms. Holgate is based on correct assumptions because an opinion based on incorrect assumptions is not very valuable, and I take it Mr. Kolesar was interested in receiving her opinion.

So I raise that now to forewarn that we intend to file that. I fully expect that the applicant may have some comments on that when we endeavour to file it and I also offer up that if there is any concern that additional cross-examination is warranted or requested, that Ms. Holgate, we would be happy to have Ms. Holgate return and respond to any follow-up questions.

MR. ROSS: Mr. Chairman, if I may, I do have some concerns with what Mr. Forster is proposing.

From what I'm hearing, and I have not yet seen what he proposes to file, but from what I am hearing, it would appear as though he is trying to get a re-presentation of Ms. Holgate on the record, and what he refers to is not simply a correction of a transcript record such as a spelling mistake or "of" to "and," but really a rerunning of his case which he's had an opportunity to do and didn't perhaps get the answer that he wanted.

Equally I would note, sir, that at the end of the day, yesterday, Mr. Forster had an attempt to try and have this precise issue on a redirect put to his witness and this Board -- this Commission made a decision
on that and that decision still stands, sir.

So in addition to trying to re-present his case, what Mr. Forster, I submit, is trying to do is effectively relitigate the decision of this Commission.

I do want to make one small point and then leave it as well, sir, with respect to the question of IRs and cross-examination.

The fact of the matter is, sir, that AltaLink put extensive IRs into this process across a whole range of parties. They were faced, as a witness panel, with some seven full days of cross-examination and in respect of Mr. Forster's witnesses, they had one day with a fairly extensive opening statement, I might add.

So any concerns he may have with respect to AltaLink's use of the IR process, I would submit, are simply unfounded.

MR. FORSTER: In response, sir, I appreciate that the Commission did conclude that my attempt at redirect was reaching beyond the norm and, indeed, I prefaced my redirect by recognizing that fact myself. That does not mean, sir, that a subsequent transcript correction by the witness is not appropriate.

And, sir, I put this in this context, sir: Any counsel appearing before this Commission has an obligation to ensure that the record is clear and that
confusions have not been created. And I am simply
devouring, sir, to ensure that the record is clear.

MR. ROSS: I might just add, sir, and
then I will leave it be, wouldn't it be nice if all of us
as counsel could have their witness heard again, perhaps to
have a second crack at correcting or taking a shot at
questions which may not be exactly the way that we had
wanted them to come out as answers. And that would appear,
sir, precisely what Mr. Forster is attempting to do.

THE CHAIR: Mr. McCreary, you're welcome
to wade in.

MR. McCREARY: Thank you, sir, I just want
to talk one thing about the procedural fairness in terms of
the way these proceedings have worked certainly since I
have been involved the last number of years. Utility
witnesses after -- for example, my cross-examination and
then other counsel is up following me, and then the next
morning they come back and they make correction to their
evidence, and it's not uncommon; it happens regularly,
quite frankly, after they read the transcript and they see,
you know what, I didn't really mean to say that. They come
back and they say either I misspoke or I want to clarify
the record. That happens procedurally on a regular basis
in virtually every proceeding I have been involved in. And
I think all Mr. Forster is saying that the witness ought to
be given that opportunity to make that correction, to make
sure the record is clear.

THE CHAIR: Thank you.

Mr. Ross, is your mic still on? Are you wanting to --

MR. ROSS: No, sir, my position to

Mr. Forster is the same as it is to Mr. McCreary, and that
is this is simply more than a just mere correction on the
record; that this is the re-presentation of evidence, and
that's simply my position, sir.

THE CHAIR: Gentlemen, what I think we'd
like to do is work this through and so we'll come back with
a ruling on that after our lunch break.

I will say, Mr. Forster, that I was pleased
with your remarks this morning and I think it speaks of the
cooperation that we have had in this hearing. So I thank
you for that.

MR. FORSTER: Thank you, Mr. Chair.

THE CHAIR: Mr. Ross, whenever you're
ready.

MR. ROSS: Thank you, sir. I'd now like
to proceed with cross-examination of the TCE panel.

Q. Mr. Unryn, Mr. Kostesky talked to you this morning a
little bit about what the definition of a customer is. I
recall at that time you made a reference, I believe, to
peanut butter, among other things, but if I may put it to you, sir, TransCanada has not provided a specific definition of what it means by customer in its rider; correct?

A. MR. KOSTESKY: We have not provided a specific definition of customer in Rider I, that is correct, but what we are referring to are customers of the AESO.

Q. But you don't make any distinction, for example, between customers who pay and who do not pay CIAC; correct?

A. MR. KOSTESKY: We don't make that specific distinction in the definition of customer. There is a customer that pays a CIAC, and there are customers who pay the AESO tariff, and obviously the customer who is paying a CIAC is also a customer paying the AESO tariff or will soon be paying an AESO tariff if they're a brand-new customer to the system.

Q. Thank you, sir. Rider I, as proposed on page 4, lines 15 through 17 of your evidence, and I will give you a moment to turn that up, if you will. It's at Exhibit 0094.00 TCE LTD 102.

A. MR. KOSTESKY: Which page number?

Q. It's page 4, lines 15 through 17?

A. MR. KOSTESKY: Yes, I have that.

Q. It's correct, is it not, that this provides a customer
with the option of converting the unamortized portion of
its existing CIAC to a Rider I payment; correct?
A. MR. KOSTESKY: With the approval of the TFO
and the AESO, which is found on line 16.
Q. I want to take you to your opening statement and the
context of what we've just spoken about, and you'd agree
with me that you've changed your position on conversion of
unamortized balances at point 5, page 1 your opening
statement; correct?
A. MR. KOSTESKY: No, that is not correct.

Point 5 in the opening statement is dealing with legacy
assets.
Q. All right. Well, in that context, would TransCanada
now support removing the conversion option set out on page
4, lines 15 through 17 of your evidence of March 6th so
that Rider I only applies prospectively? Is that your
position?
A. MR. LEVSON: I think maybe I can help you
on that. First of all, in the previous question, we're not
changing our position; we're just clarifying our position.
So everything is as has been proposed.

Can you repeat that last question again, please?
Q. Certainly. Would TCE now support removing the
conversion option set out on page 4, lines 15 through 17 of
your March 6, 2009 evidence, so that Rider I only applies prospectively? Is that now your position?

A. MR. LEVSON: No. Let me just take a minute to explain what that clarification is about in item 6 on the same page.

All we were saying there with that revision, is that during the course of construction, when the TFO is building the facilities for the customer, the current practice is that before major construction starts, the customer has to put up the customer contribution.

So what we're saying is that that practice should continue. And at the time when the facility is interconnected, like the last part of that sentence on line 10, the time of interconnection, energization, when it becomes used and useful, at that time the Rider 1 could be initiated, so the -- if it meets the tests.

And so the contribution that was made earlier in the project during that period would be refunded to that customer. And there's a very clear reason for this, and that's that the default risk that we had contemplated during the course of developing this rider, we considered to be minimal, because it was after the facility was energized. We did not want -- we do not want customers to have to bear the default risk during the construction period of a plant. That is the time when default is more
likely to happen. Plans can change; customers, you know, are in financial difficulties.

So that's the fine-tuning that we did that revision.

Does that assist you, Mr. Ross?

Q. Yes, it does, sir.

Mr. Kostesky, in your opening statement, you indicate that there might be a possible change to prepaid operation and maintenance costs. Correct?

A. MR. KOSTESKY: Yes.

Q. However, the Commission's predecessor, the AEUB, previously decided to impose a 12 percent prepaid operation and maintenance charge for standard transmission facilities; correct?

A. MR. KOSTESKY: That's correct, but it's under a review and variance application today.

Q. But that decision is currently in force; correct?

A. MR. LEVSON: That's correct. The customer today would pay that 12 percent --

Q. Thank you, Mr. Levson.

A. MR. LEVSON: -- subject, to, of course, the review and variance application.

Q. Thank you, sir. Can we agree that the AESO, A-E-S-O for the record, may not be filing its 2010 tariff until at least the third or fourth quarter of 2009?
A. MR. KOSTESKY: Yes.

Q. Mr. Kostesky, it may well be later than that? It may well be early 2010, even into the first and second quarter of 2010; correct?

A. MR. KOSTESKY: Again, I can't speculate as to when it will be. That's in the AESO's camp. But every indication we've got from them, it will be in the second or third quarter of 2009.

Q. Mr. Levson, you've been involved in a number of Alberta Utilities Commission and AEUB hearings; correct?

A. MR. LEVSON: Yes.

Q. In your experience, a Commission hearing on a GTA may not take place until several months after filing; correct?

A. MR. LEVSON: Yes, the filing would trigger the process, and it could be a few months before you get into a proceeding, the oral part of the proceeding, anyways.

Q. Thank you, sir. A Commission decision on the AESO 2010 GTA could be issued several months even after that, after that oral hearing; correct?

A. MR. LEVSON: Yes, the kind of rule of thumb that we understand is that within 90 days of the close of the hearing, the Commission will render a decision. I'm not saying that that always happens, but that's roughly the rule of thumb we use.
Q. So, sir, to the extent that Rider 1 is dealt with in this Commission's decision in a future AESO GTA, it may be a year or more from today before a decision on Rider 1 is rendered; correct?

A. MR. KOSTESKY: Yes, that's possible; but we've also addressed that in our opening -- in my opening statement, indicating that the Commission can initiate an earlier module of that AESO 2010 GTA, if it found a sense of urgency to deal with the management fee issue in front of it today.

Q. Mr. Kostesky, can you explain to me what evidence the AESO has filed in this proceeding -- the AltaLink '9/'10 GTA, with respect to a potential modulized or modular hearing on Rider 1?

A. MR. KOSTESKY: They have not, to my knowledge.

Q. Thank you, sir. Mr. Kostesky or Mr. Levson, both of you are familiar with the AESO's 2010 GTA stakeholder process; correct?

A. MR. KOSTESKY: Yes.

Q. That process is not yet complete; correct?

A. MR. KOSTESKY: It is ongoing; that's correct.

Q. As a general principle, an ongoing GTA stakeholder process could involve, among other things, consultation
working groups; correct?
A. MR. KOSTESKY: Yes, that's correct.
Q. Stakeholders meetings?
A. MR. KOSTESKY: Yes.
Q. Policy recommendations?
A. MR. KOSTESKY: I'll leave the mic on. Yes.
Q. Revisions to those recommendations?
A. MR. KOSTESKY: Yes.
Q. Further AESO consultation?
A. MR. KOSTESKY: Typically, yes.
Q. Therefore, can we agree that the AESO's as yet incomplete stakeholder consultation on its 2010 GTA may be an extensive and time consuming process?
A. MR. KOSTESKY: I can't comment on whether it will or won't. They're initiating their process, and they have established a need to populate working groups to deal through these issues.
However long those working groups take to get through the issues will determine the timeline on, you know, providing those recommendations to the AESO for their application.
Q. Fair enough. But that list of related process we've talked about, that takes time; doesn't it? That takes significant time?
A. MR. KOSTESKY: I won't agree with
"significant." It takes time.

Q. All right. Proposals within the AESO's GTA stakeholder process may ultimately not be filed as part of its GTA; correct?

A. MR. KOSTESKY: Yes.

Q. It's the AESO and not TransCanada or TCE who controls the content and timing of the AESO GTA 2010 filing; correct?

A. MR. KOSTESKY: Yes, that's correct.

Q. So on the basis of that, it's possible, is it not, that Rider 1, in the form you propose, may well never get before this Commission as part of the AESO's 2010 GTA?

A. MR. KOSTESKY: I guess in absolute terms, that's a possibility, yes.

A. MR. LEVSON: Let me just add to that: that a lot of work has gone on in this matter for coming up a year now, dealing with these issues. And when you look at the evidence that we did file in this through the AltaLink working group, which was expanded to include virtually everybody in the industry towards the end of that process, there was a lot of support for the proposal; and the AESO was a part of that; and the AESO has brought that forward.

There is a document available on the AESO Website, that we could provide, that outlines where they're
at and shows Rider I. It's a serious -- it's a serious proposal, Mr. Ross, and we expect to see AltaLink as well as ourselves supporting it.

Q. I appreciate that, Mr. Levson. But I thought we had agreed that proposals within the AESO's GTA stakeholder process may be subject to change -- correct -- before ultimately being filed by the Commission?

A. MR. LEVSON: Yes, absolutely, as we go through this process, we'll look at all of these things that have been discussed this morning, around the ten years, the 20 years, the various aspects of it. We will try to come up with best proposal possible, and hopefully we, including the AESO -- the AESO will take that forward.

But I have not heard -- even the one party that was opposed in the AltaLink process was not opposed to -- in their discussions with me -- they were not opposed to Rider 1 in principle; they just wanted it to be dealt with in the AESO GTA, is what they've indicated to me.

So I think this idea is fairly simple. It seems to have fairly wide support. I'm not saying everybody agrees with it, but I think -- my judgement is this is going forward; this is very likely going to happen.

Q. But there is a chance that it may be subject to change or may not reach this Commission at all in the form of Rider 1; correct?
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A. MR. LEVSON: It's absolutely possible that that could happen. You know, anything in the future -- it's hard to say anything will happen for sure in the future.

MR. ROSS: Thank you, sir. Thank you for your time. I have no further questions for this panel.

THE CHAIR: Thank you, Mr. Ross.

Ms. Ramdin.

MR. RAMDIN QUESTIONS THE PANEL:

Q. Good morning, panel. Mr. Kostesky, I think it was you this morning with Mr. Ross, and you were discussing the scenario analysis that you did, three different scenarios?

A. MR. KOSTESKY: Yes, I recall that.

Q. I recognize this was not previously filed in evidence; however, it was raised on the record, and we feel that it could be of assistance in further understanding the issues raised by these witnesses. So in the interest of fairness to the applicant, we'd ask that perhaps you file this as an undertaking. The applicant would be allowed to propose questions -- or the applicant would be allowed to pose questions in writing on this documentation.

MS. BERGE: I think we can undertake to provide that, to assist the Commission.

MS. RAMDIN: Thank you.
UNDEARTAKING - TO PROVIDE THE THREE SCENARIOS DISCUSSED.

Q. MS. RAMDIN: Does TransCanada share AltaLink's view that a margin-owned CIAC is warranted, or is TransCanada proposing Rider 1 on the basis that AltaLink has claimed there's a problem that needs to be addressed?

A. MR. KOSTESKY: TransCanada is sympathetic to the position that AltaLink is in with the increasing levels of CIAC, but we feel that the management fee may not be the most effective way of dealing with it. Hence, we've put forth Rider 1 as an alternative worth considering.

And we feel that the Rider 1 will address not only the TFOs' concerns, but also the customer's concerns.

Q. Thank you. On page 2 of your opening statement, TransCanada states:

"TransCanada believes that a sufficient number of customers with CIAC amounts will qualify and opt for Rider 1, so that the TFO's concerns of having the CIAC as a large percentage of their rate base will be addressed."

What is "a sufficient number of customers"?

A. MR. KOSTESKY: We don't have a specific number, because we don't have access to how many actual customers comprise of the amounts that are on the TFO's
books for CIAC. But we would expect that through the creditworthy test and with the discretion of the AESO or the TFO to finance these amounts, that we would bring the ratio of the CIAC to rate base below what has been referred to as the "bright line 10 percent." I think that's what we are referring to, is "sufficient," maybe is the right word, number of customers to affect the ratio in a positive way.

Q. Thank you. Can you please turn up Exhibit 111.01, which is IR response ASBG/PGA-TCE 2 C.

A. MR. KOSTESKY: That was 2 C?

Q. Yes, it was.

A. MR. KOSTESKY: Yes, we've got it.

Q. I'm looking at the bottom of page 2; and in speaking about Rider 1, TCE states that it does not anticipate that the administration required would be significantly different than that required for the management fee, particularly if the management fee is administered on an individual customer basis.

I was wondering if you could describe what your understanding is of the administrative complexity that would be required by either AltaLink or the AESO if the management fee proposal were adopted.

A. MR. LEVSON: Let me take a crack at that.

So that statement, of course, is conditioned
on the assumption that the management fee goes to the individual customer that caused the contribution in the first place.

That is a matter that we believe will be debated if this management fee is approved; will need to be debated in the AESO GTA, because right now it's just, as we understand, a lump sum amount.

If it does go to the individual customer, then the TFO will need to track the management fee for each customer on their books. And so they will have to do that customer by customer, specifically, which they would have to do with our proposal as well.

Q. Mr. Levson, in your discussion this morning with Mr. Unryn, you described a scenario where a large customer receiving Rider 1 treatment of a customer contribution goes bankrupt.

In your explanation, you seemed to suggest that AESO customers can take comfort from the fact that the bankrupt entity would still have assets, and that the next purchaser of the assets would still require electrical service; is that correct?

A. MR. LEVSON: Yes, that's right.

Q. In this scenario, would the new purchaser of the bankrupt customer's operations resume with the bankrupt customer's Rider 1? Or should the new customer revert to a
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- Questioned by Mr. Ramdin

lump for any unamortized portion of the contribution?
A. MR. LEVSON: That's a good question. I don't know that we have thought about that detail a lot, but I would -- the common sense would suggest at least one test would be the creditworthiness of the new customer that's taking over those assets. So if they were deemed to be creditworthy, then it would make sense that they could just continue on with payments.

If they weren't creditworthy, then a lump sum would be appropriate at that time.

Q. Thank you. I think, staying with you, Mr. Levson, also in your discussion with Mr. Unryn this morning, you were discussing the possible conversion of legacy contributions into Rider 1 payments. You suggested that these conversions might also be limited to the creditworthy customers.

Could you perhaps provide a ballpark estimate of the proportion of legacy contribution on AltaLink's books that would be sufficiently creditworthy to be converted to Rider 1 payments?

A. MR. LEVSON: That would be very difficult for us to do. We don't even know, really, the names of the customers that have these contributions. We would know TransCanada's, of course. But that's information that would be available to the AESO or to AltaLink.
But if it's of assistance to you, in general, I would say, again, that the type of customers that attach at a TFO level -- you know, you're talking 10 to 25 to 50 megawatts, typically -- these are very large loads with large plants behind them, typically, if they're industrials; if they're DFOs, of course, we understand their circumstances.

So I think the bulk of them are going to be creditworthy, but on the load side. A little bit more concern we would have on the STS side, on the supply side. Because some of those customers, such as wind and biomass -- would be examples -- would be perhaps more on the edge financially. So that's where that creditworthiness test would be very important to be applied.

Q. Does the TFO maintain a record of the identity of customers who have contributed assets on their books?
A. MR. LEVSON: I believe we answered that in one of the information responses; but, yes, it's our understanding that they do.

I think the reason they do is that they have to be prepared to refund it if those assets are shared with somebody else or, you know, circumstances like that arise.

So it's my general understanding, from my previous employment, I guess, that that is the case.
Q. Thank you. On Tuesday, Ms. Wall was speaking with Mr. Frehlich, and she posed a question in relation to AltaLink's station service PSRM project, S-2-18. And it was in the transcript, and it was Volume 7 of the transcript -- and I don't think you need it, but if you do, just let me know -- around pages 1141 to 1142.

Mr. Crnkovic stated that the AESO had adopted a new standard for 240 kV substations. Are you familiar with this new standard?

A. MR. LEVSON: No, I don't think we are.

MS. RAMDIN: Okay. Thank you, that's all my questions. Please answer the questions of the Commission Panel.

THE CHAIR: Thank you, Ms. Ramdin.

Mr. Kolesar?

MR. KOLESAR QUESTIONS THE PANEL:

Q. Thank you, Mr. Chairman. I'm almost afraid to ask any questions, but I will try anyway. I just have two, I think two.

I was a little unclear, gentlemen, your answer to the first question from Ms. Ramdin about whether or not you agree in principle that the TFO should be allowed to make an equity return on their CIAC.

A. MR. KOSTESKY: That's a very good question.
And I think, when you look back at the levels of the CIAC amounts, they didn't seem to be as problematic until they hit a fairly high level, relative to rate base. And one can look at the absolute levels as well.

So it appears that when you get above 10 percent -- and that's 10 percent of the rate base -- it becomes perhaps problematic from the TFO. So although they're sympathetic that they have these assets that aren't earning a return, we think that with a larger rate base or a lower CIAC amount, or even both, and if we fall below the 10 percent, that the concern significantly diminishes to the levels they were before we got to, you know, this concept of having a management fee provide a return.

So I would say that if the trend conditions, it's something that needs to be addressed, but there's many ways to address that concern.

Q. Thank you for that very pragmatic answer, but it kind of skirts what I really asked you. In principle, as a matter of principle, do you agree with Dr. Cicchetti that the TFO should be able to earn an equity return on CIAC?

A. MR. LEVSON: Yes, I don't -- I don't think, in principle, we would agree that appropriate level of compensation for the TFO, should this Commission determine that a management fee is appropriate, is at that
level. It's the return on equity; plus, as I have said, it's the income tax component. When you look at those numbers, they're very large, relative to virtually -- like, there is no additional service that we're getting. So we really struggle with the level.

Other parties, and in the ATCO case, other parties there as well, put forward alternate calculations for the management fee that are considerably lower and more reasonable, in our view, for what we think this kind of problem would attract.

But just to come back to Mr. Kostesky's comments, we just think there's a way better way to solve this problem.

Q. Okay, I guess I will let that line of questioning go for now.

I have a question about the mechanics and, in particular, the mechanics of your proposal that the legacy or embedded balance of CIAC -- it could be converted to a Factor I. I'm wondering if you could enlighten me somewhat on exactly how the mechanics of that might work.

A. MR. KOSTESKY: So just so that I understand the question correctly, if we were to run through a scenario of an unamortized CIAC balance that's on the books today with an asset that's up and running -- and let's say that the asset has been running for three years, and
there's some unamortized components sitting on the TFO books that would convert to Rider 1. Is that the question?

Q. Yes, I'm trying to figure out how the conversion would work. So just so we are sure we're talking about the same thing, if there's a particular company that has an unamortized balance and they want to convert it to Rider 1, how would the mechanics of that work?

A. MR. KOSTESKY: So in the undertaking, we'll provide some tables as to how those are calculated.

But, in essence, if we just assume, for sake of this discussion, that there's an unamortized balance of a million dollars, the TFO would raise the funds or take it out of their existing pool and pay the customer the million dollars in return for a Rider 1 obligation of payments amortized over the life of the asset or the remaining life of the asset, which would be the return on and the return of the million dollars that the TFO would give to -- refund back to the customer.

Q. So the TFO has to raise the money to pay it back to the customer so the customer can, in turn, turn it into a Rider 1? Is that what would happen?

A. MR. KOSTESKY: In essence, yes, that's what would happen, is that the TFO would then fund the repayment in return for an amortized payment stream.

Q. Where is the TFO getting the money from?
They can get it either from internally generated funds or from obtaining financing in the external markets, just as they do with normal rate base additions. This would just be another component of financing for them.

Q. Just two more quick things. One is, given the discussion at this proceeding with respect to the deteriorating metrics for AltaLink, does this make sense at this time?

A. MR. KOSTESKY: Well, I'd refer to Exhibit 226, which is an AltaLink undertaking to provide the calculation relating to how the matters discussed would have an impact on the credit ratings. And my reading is -- is that it would actually be supportive of the credit metric.

I think the fundamental reason why it would be supportive -- when you kind of read it through and summarize -- it's because the asset is immediately generating cash flow.

Q. Okay. And my last question is: In the mechanics of the conversion of the remaining balance of CIAC to a Rider I, there's an assumption in there that in the TFO's accounting, they have actually kept track of every single company and all the balances for every single company. Do we know that they have actually done that, or is it just
one big account, and you dump all your CIAC in there and you gradually amortize it? Do we know that the companies would actually be in a position to do that?

A. MR. LEVSON: Let me take a crack at that one. It's a good question. We're not the TFOs, obviously, so we're not apprised of all of the details of their accounting practices.

As I said earlier to Ms. Ramdin, it's our understanding that they have to keep track of the contribution, the original contribution.

So what I think you're pointing to is do we know how that contribution has been amortized over time so they will know when it came in and how much it was. So maybe, say, three years later, they will have to do a calculation.

The piece that they need to have is the amortization of the contribution. That number, from my understanding of how the TFOs work, is a number that's approved. Like it's a number -- it's usually around 3 percent. I think I have seen numbers that are 3.5 and 3.7, but it's a known number. So they would take that percentage, apply it to the original contribution for the number of years that that amortization was in place and then end up with an unamortized balance. In the case of a million dollars, it might be say $900,000.
So I think that's a calculation that they can do fairly easily because the amortization rates are used across the board for the contributions. That's my general understanding.

A. MR. KOSTESKY: If I might add to that. I certainly know who does have the numbers, and that's every customer. TransCanada has an account of what we've contributed into that account. So that's a pretty good starting point as well.

MR. KOLESAR: All right. Thank you very much. That concludes my questions, Mr. Chairman.

THE CHAIR: Thank you, Mr. Kolesar.

Mr. Lyttle?

MR. LYTTLLE QUESTIONS THE PANEL:

Q. Thank you. Good morning, panel. Just a few.

On that section, lines 15 to 17, which is I think in your evidence, you don't have to turn to it, but it's point number 9.

"Unamortized balances of existing contribution could be converted to Rider I on a one-time basis, so those are the historic ones, at some point after Rider I is approved and with the approval of the TFO and AESO at those parties' sole discretion."

I was wondering where the customer's
discretion comes into this. You didn't mention that, and I
don't know if you include that in another part of your --
but I just picked up that obviously on an historical basis,
and with all the different tax treatments, et cetera, that
customers have, there would be a lot of consideration of
what they want.

A. MR. LEVSON: Yes, the discretion that the
customer exercises is a decision whether he wants to apply
for Rider I or not. He may take into account all the
considerations that you mentioned, his tax situation, his
cost of capital.

Q. But these are for the historical legacy assets I think
we're talking about here.

A. MR. LEVSON: That's correct.

Q. So the customer would still have to apply. That would
be the process with the application?

A. MR. LEVSON: That's right. He would apply
for Rider I and then the AESO would be the first test to
see if he's creditworthy, and then if he passes that test,
then it would go to the TFO to determine whether they can
handle it in their financing. As we said before, they
could say yes or they could say later or they could --

Q. So legacy assets would only be converted at the first
discretion of the customer?

A. MR. LEVSON: That's right, yes. To be
clear, this was one of the trade-offs. There was a recommendation, a caveat in one of the working group members that it be forced on customers, that they had to convert to Rider I and we just didn't think that would work with the creditworthiness test at the same time.

How can you, one, say we're only going to give it to you if you're creditworthy, but oh, by the way, you have to take it. So we just didn't think that worked, so we've given the discretion to the customer initially.

Q. Right, thank you.

If you can turn up EPS 1-11, I think it's Mr. Unryn's IRs back and forth, 12-1 C. And there you were talking about the STS and DTS customers, but a line at the bottom caught my attention. I will read you the whole paragraph. It's just two lines:

"As a result of the foregoing, STS customers should be availed the same amortization options as DTS customers. Furthermore, the Rider I proposal places STS customers who meet the AESO creditworthiness test on a more level playing field with PPA generation."

That last line, could you explain that or expand upon that some more.

A. MR. LEVSON: Mr. Lyttle, I don't think we have the same reference here. We're in 12 and I couldn't
1. see those --
2. Q.  12-1.
3. A.  MR. LEVSON:  12?
4. Q.  So EPS 111, 12-1 and your answer C. It's the last --
5. it's just before item 2, the last paragraph.
6. A.  MR. LEVSON:  I'm sorry, sir, it was the
7. last paragraph, C, the one that starts out "as a result
8. of"?
9. Q.  The last paragraph, the very last line, referring to
10. PPA generation and the more level playing field. Could you
11. expand on that?
13. Q.  Where is that going?
14. A.  MR. LEVSON:  Well, you know one of the
15. things that the AESO look for in a market is levelness
16. between various generation players, and right now, all of
17. the PPA generation has the cost of interconnection spread
18. over time through the RGUCC payment. So they did not have
19. to make an upfront payment for that.
20. Today, a new generator coming on the system
21. has to pay 100 percent of the cost upfront. And that is an
22. area of discipline that Mr. Unryn and I didn't get into,
23. but that definitely is an area of discipline, that total
24. capital amount.
25. So if there was an opportunity to levelize
it, it puts it on a similar financial basis as to what the
PPA generation enjoys.

Q. So you're really talking about historic -- legacy
people versus new entrants?
A. MR. LEVSON: That would be a reasonably
fair characterization of it, yes.
A. MR. KOSTESKY: But the comment here,
Mr. Lyttle, was to level the playing field between the PPA
generators or the buyers of the PPA output and non-PPA
generators. That was what the context of that comment was
for, but on all for legacy assets because the PPAs were
struck in 2001 and there is no new PPAs per se.
Q. Okay, thank you.

The last area that I wanted to look at was
on this default risk idea, I note that you had said default
risk is managed down by having a large number of customers
that you spread it over. You said that at the start. I
think that was part of your opening statement.

I know I worry more about systemic risks
than I ever worry about individual risks, because
correlated risks I'm sure we've had lots of information
here about that during the hearing, and how things tend to
fall over all at the same time, but I was thinking about --
in relation to Mr. Unryn's question about the risk -- and
there is some residual risk, as you even admit by only
admitting creditworthy customers to be available for the Rider I program, but in the risk in the Rider I program, I was thinking of the difference between a plant that has no CIAC people in it and a plant that does have some 10 or 20 percent. When both of those go bankrupt, the risk is still on the whole component of that plant that's there and that's the risk that is already present and the whole system bears. And the only difference that we're looking at here is that a portion of that whole risk is not going to be prepaid. Am I viewing that correctly?

A. MR. LEVSON: Yes, think that's correct.

Customer A who had a $10 million cost and investment completely covered it, they have no contribution, compare that to customer B. Say they had a $12 million contribution, 10 million is covered by the investment policy. So there's 2 million CIAC, which is prepaid, in my example. And if both of those customer A and customer B go bankrupt and there's nobody picking up the assets and so we're left with those assets to be recovered, they're both going to be recovered in the same way through -- the rest of the customers are going to have to bear the cost of whatever can't be recovered through salvage and so on. So the extra risk is going from the 10 to the 12.

Q. But the system already has the risk on the main plants?
A. MR. LEVSON: That's our understanding. That's certainly the TFO's understanding. That's my understanding. The only caveat I would have in that is because we haven't had one of these happen, we really don't have a precedent, but I find it very difficult to figure out how you can take that default and land it with anybody other than the rest of the system. I don't think you can move it back to the TFO under the current structure.

Q. Yes, I think it's beyond me. Maybe the credit rating agency's will have a go. I'm sure they find default risk anyways. Anyways, thank you for your answers today.

A. MR. LEVSON: You're welcome.

THE CHAIR: Thank you, gentlemen. That's all of our questions.

MS. BERGE: No thank you, Mr. Chairman. We have nothing.

THE CHAIR: Wonderful. Once again, thank you for being here with us today. Thank you for your direct answers. You're dismissed.

(THE PANEL STANDS DOWN)

THE CHAIR: So we are now at 5 to 12. I actually would like to start the panel and get on with the show. So I understand we have --

Is Mr. Marcus the next up, Ms. McKenzie; is
Undertaking:

To provide the three scenarios discussed at pages 1553 and 1554.

Response:

TransCanada has conducted a comparative analysis of the costs that would arise from a customer perspective under the following three scenarios:

1. **Status Quo** - CIAC payments continue to be assessed based on the current AESO tariff and financed by the customer utilizing the same cost structure as the TFO.

2. **Management Fee** - Status Quo plus AltaLink's proposed Management Fee.

3. **Rider I Alternative** - The CIAC payment is converted to a traditional cost of service payment over time through the Rider I mechanism. The TFO invests in the asset and costs are recovered from the customer through Rider I payments. No Management Fee is payable.

Assumptions:

TransCanada’s analysis is based on Table 3 of AltaLink’s Rebuttal Evidence at page 57 [Exhibit 135.01]. For comparative purposes, TransCanada assumed the following:

- the CIAC amount is $1,000,000.

- the customer's cost of capital is the same as AltaLink's. For the analysis, a debt/equity ratio of 60/40 was assumed and a return on equity of 8.75%.

- the cost of the Management Fee would be assigned to the customer that triggered a Customer Contribution; however, who would ultimately pay the Management Fee has yet to be resolved. Regardless, some group of customers will be required to pay this amount.

- the Rider I Alternative repayment term is 30 years to provide comparability with Scenarios 1 and 2. Although TransCanada proposes a shorter term in its Rider I Alternative, the outcome, in present value terms, does not change whether 20 or 30 years is used for the repayment term.
Table 1 - Comparison of AltaLink Management Fee Proposal to Status Quo and Rider I Alternative
Prepared by TransCanada

<table>
<thead>
<tr>
<th></th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
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<tr>
<td></td>
<td>Status Quo</td>
<td>Status Quo</td>
<td>Rider I Alternative</td>
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<td>Customer costs:</td>
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<td>Customer Contribution - Financed over 30 years</td>
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<td>$2,275,867</td>
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<td>Management Fee - Payments over 30 years</td>
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<td>Rider I - Payments over 30 years</td>
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<td>33%</td>
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**Nominal Dollar Comparison**

1. In TransCanada's analysis, nominal dollars represent the sum of the amounts that are incurred in each year of expenditure.

2. In TransCanada's analysis, present value calculates a series of payments discounted to reflect the time value of money according to a discount rate. In this comparison, the present value payments were calculated using a discount rate of 8.2314% (the 2009 Pre-Tax Rate of Return in Table 3 of AltaLink's Rebuttal Evidence at page 57).

**Notes:**

1. In TransCanada's analysis, nominal dollars represent the sum of the amounts that are incurred in each year of expenditure.

2. In TransCanada's analysis, present value calculates a series of payments discounted to reflect the time value of money according to a discount rate. In this comparison, the present value payments were calculated using a discount rate of 8.2314% (the 2009 Pre-Tax Rate of Return in Table 3 of AltaLink's Rebuttal Evidence at page 57).
Scenario 1 - Status Quo
Prepared by TransCanada

2009 Pre-Tax ROR (30 Years)

Principal: $1,000,000
Pre-Tax Rate of Return: 8.2314%
Average life of Transmission Assets: 30

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Total: $ 1,000,000 $ 1,275,867 $ 2,275,867

Present Value: $ 367,213 $ 632,787 $ 1,000,000

Notes:
1. The annual Payment of Principal is $1,000,000 divided by 30 years.
2. The annual Return "On" Investment is calculated by multiplying the principal at the beginning of each year by 8.2314%.
### Scenario 2 - Status Quo Plus Management Fee

Prepared by TransCanada

**2009 Pre-Tax ROR (30 Years)**

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<th>Payment of Principal (Return Of Investment)</th>
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**Total:** $1,000,000 | $1,275,867 | $2,275,867 | $753,472

**Present Value:** $367,213 | $632,787 | $1,000,000 | $373,697

### Notes:
1. The annual Payment of Principal is $1,000,000 divided by 30 years.

2. The annual Return "On" Investment is calculated by multiplying the principal at the beginning of each year by 8.2314%.

3. The Management Fee is calculated by multiplying the principal at the beginning of each year by the equity portion of the return (adjusted for income tax) of 4.8611%. (40% * 8.75% / (1 - 0.28)). Note that TransCanada's total of $753,472 does not match exactly with Dr. Cicchetti's value at the top of page 58 of AltaLink's Rebuttal Evidence primarily due to differences in the equity portion (38% versus 40%). 40% was used to maintain consistency between the Scenarios.
# Scenario 3 - Rider I Alternative

Prepared by TransCanada

## 2009 Pre-Tax ROR (30 Years)

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<th>Annual Return (Return On Investment)(^2)</th>
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Present Value: $367,213 $632,787 $1,000,000

Notes:

1. The annual Payment of Principal is $1,000,000 divided by 30 years.

2. The annual Return "On" Investment is calculated by multiplying the principal at the beginning of each year by 8.2314%.
AML – TCE 1

Reference: Exhibit 0271.01 TransCanada Energy Ltd.’s (“TransCanada”) response to undertaking at transcript reference volume 9, page 1576

Request:

Confirm that it is unlikely that customers' capital structures and costs of capital will be the same as AltaLink's.

Response:

Although TransCanada is not aware of particular customers’ capital structure and cost of capital, TransCanada agrees that it can be reasonably assumed that the cost structures and costs of capital of AESO customers will not be identical to AltaLink’s. However, such cost structures and costs of capital may be similar, depending on the type of entity involved.

The reason TransCanada used a constant cost structure and cost of capital in its analysis was to allow an appropriate comparison of the costs of the proposed Management Fee to the Status Quo or Rider I. Regardless of the cost of capital assumed for the customer, the Management Fee proposal will be more expensive to the customer than the Status Quo. In situations where a customer’s cost of capital is greater than or equal to AltaLink’s cost of capital, the Management Fee proposal will be more expensive to the customer than the Rider I proposal.1

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1 For cost comparisons from a customer’s perspective, TransCanada used the customer’s assumed cost of capital as the appropriate discount rate for all present value calculations.
AML – TCE 2

Reference: Exhibit 0271.01 TransCanada Energy Ltd.’s (“TransCanada”) response to undertaking at transcript reference volume 9, page 1576

Request:

Confirm that for any customers that do not hold "A" category credit rating, it is reasonable to assume that such customer's cost of capital will exceed AltaLink's cost of capital.

Response:

TransCanada is unable to provide a specific opinion as to the impact of credit ratings on customers’ cost of capital, as the cost of capital will be affected by a number of different variables. To the extent that a customer’s credit rating is lower than the “A” category, TransCanada would generally expect that its cost of capital will be higher than where the credit rating is “A” category or higher, all else being equal.
Alberta Utilities Commission

IN THE MATTER OF the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2,

IN THE MATTER OF the Electric Utilities Act, S.A. 2003 c. E-5.1;

AND IN THE MATTER OF an application by AltaLink Management for the approval of its revenue requirement, deferral and reserve accounts for the period commencing January 1, 2009 to December 31, 2010;

AND IN THE MATTER OF Application No. 1587092, Proceeding No. 102.

____________________________

Final Argument

of

TransCanada Energy Ltd.

____________________________

June 15, 2009
1.0 MANAGEMENT FEE ON CONTRIBUTIONS IN AID OF CONSTRUCTION

1.1 Introduction

1.1.1 TransCanada Energy Ltd. (“TransCanada”) has participated in AltaLink Management Ltd.’s (“AltaLink”) General Tariff Application (“GTA”) to respond to AltaLink’s Management Fee proposal. As such, TransCanada’s argument will be limited to addressing the Management Fee requested by AltaLink and TransCanada’s proposed alternative, Rider I.

1.1.2 TransCanada submits that AltaLink’s proposed Management Fee should be denied. The more appropriate manner in which to deal with AltaLink’s concerns regarding an inability to earn a return on assets currently funded by customers through Contributions in Aid of Construction (“CIAC”) is to permit transmission facility owners (“TFOs”) to invest in these assets and earn a return over time. TransCanada has proposed that this be done through Rider I, which would be less costly to customers than the Management Fee proposal and would better balance the interests of TFOs and customers.

2.0 NEED FOR MANAGEMENT FEE

2.1 TransCanada submits that the proposed Management Fee is not needed because there is a superior solution to the issues underlying the Management Fee proposal. TransCanada acknowledges that CIAC may be problematic for TFOs to the extent that CIAC amounts grow significantly relative to the TFOs’ rate base; however, increasing CIAC payments are also a concern from a customer standpoint, as customers are required to make increasingly large up front contributions for assets over which they have no ownership or control. Rider I would be a less costly mechanism that, unlike the Management Fee, would address the concerns both of TFOs and customers by aligning investment with ownership and control.

2.2 Further, there are additional factors that should address AltaLink’s concerns by lowering CIAC as a percentage of rate base, including:

1 Transcript page 1582, lines 1 through 16; page 1576, lines 7 through 14.
2 Exhibit 256; Exhibit 110, Attachment AUC-TCE 1(a) at page 16 (page 10 in Appendix A).
i. The Alberta Utilities Commission (the “Commission”) is currently considering a review and variance application in relation to the 12 percent prepaid Operating and Maintenance charge within the context of the Alberta Electric System Operator’s (“AESO”) contribution policy. If the Commission removes this charge from the AESO investment in standard facilities, customer contributions will be further decreased;\(^3\)

ii. Completion of AltaLink’s predicted major capital projects over the next several years will result in major additions to rate base that are likely to significantly reduce the amount of CIAC relative to rate base;\(^4\) and

iii. A change to the current AESO investment policy could also reduce the amount of CIAC relative to rate base.\(^5\) Recommendations regarding a change to this policy arising from the AltaLink-led Working Group are being considered as a part of the AESO’s 2010 GTA consultation process.\(^6\)

3.0 MANAGEMENT FEE PROPOSAL

3.1 The proposed Management Fee would be more costly than the status quo, as it represents a new charge of $5.5 million for 2009 and $7.0 million for 2010.\(^7\) For 2010, the total Management Fees applied for by AltaLink and ATCO Electric Ltd. (“ATCO”) are over $12 million.\(^8\) If the Management Fee is approved, a specific group of customers will be required to bear the cost of the Management Fee on an annual basis. Contrary to the suggestion of AltaLink,\(^9\) TransCanada submits that it would be inappropriate for the Commission to determine which group of customers should bear this cost as a part of this proceeding. The proposed Management Fee, if approved, would form part of AltaLink’s revenue requirement; however, its collection from AESO customers would occur through the AESO’s tariff.\(^10\) Therefore, TransCanada submits

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\(^3\) Application No. 1566390, Proceeding ID 108.
\(^4\) Exhibit 256.
\(^5\) Transcript, page 448, lines 7 through 25; page 449, lines 1 through 21.
\(^6\) Exhibit 110, AUC-TCE Attachment 1(b), page 3; Transcript, page 1572, lines 14 through 21.
\(^7\) Exhibit 94, page 2, Table 4.
\(^8\) Exhibit 94, page 2, lines 2 through 4.
\(^9\) Transcript, page 455, lines 2 through 6; page 455, line 21 to page 456, line 3.
\(^10\) Exhibit 111, response to ASBG/PGA-TCE-10.
that the AESO GTA is the proper forum in which to deal with AESO rate design, with input from all interested parties.

3.2 Should the Management Fee be approved, TransCanada anticipates that the issue of who should pay for this significant new cost will be hotly debated in future AESO GTAs.\textsuperscript{11} In TransCanada’s view, the following are possible outcomes of the question of “who pays” the Management Fee in the event that it was approved:

i. The Management Fee could be allocated to all AESO customers on a pro-rata basis.\textsuperscript{12}

ii. The Management Fee could be assigned to the specific customer triggering the CIAC amount, in which case the customer will be required to pay its share of the Management Fee in addition to raising its CIAC contribution.\textsuperscript{13}

iii. Both (i) and (ii) would be affected by the question of whether the Management Fee could be assigned to Demand Transmission Service (“DTS”) customers only.\textsuperscript{14} Section 47(a) of the Transmission Regulation\textsuperscript{15} requires that the AESO tariff ensure that the “just and reasonable costs of the transmission system” are “wholly charged” to load customers. To the extent that the Management Fee were determined to be a cost of the transmission system pursuant to section 47(a), it would not be permissible under the regulation to charge it to Supply Transmission Service (“STS”) customers.

3.3 The question of how a Management Fee would be allocated is an important issue that will have varying impacts on customers, depending on the outcome. TransCanada notes that the question of allocation does not arise with Rider I, as the customer triggering the CIAC payment would be responsible for the Rider I payments.

\textsuperscript{11} Exhibit 111, response to ASBG/PGA-TCE 10.
\textsuperscript{12} Exhibit 111, response to ASBG/PGA-TCE 8(a).
\textsuperscript{13} Exhibit 111, response to ASBG/PGA-TCE 8(a).
\textsuperscript{14} Exhibit 111, response to ASBG/PGA-TCE 8(a).
\textsuperscript{15} AR 86/2007.
4.0 RIDER I PROPOSAL

4.1 As a result of the recommendations of the AltaLink-led Working Group, the AESO has advanced the Rider I concept as a part of its consultation for the AESO 2010 Tariff Application\textsuperscript{16} and has established working groups to deal with it and other CIAC-related matters.\textsuperscript{17} TransCanada notes that there has been significant effort expended to date to develop the Rider I concept by various industry players, and as such, Rider I will likely find support in the AESO GTA process.\textsuperscript{18} Indeed, the proposal has the support of AltaLink, who testified that it will continue to support Rider I.\textsuperscript{19}

4.2 TransCanada is not applying for approval of Rider I in this proceeding, but has attempted to put forward as much detail as possible regarding Rider I to demonstrate that it is a credible alternative to the Management Fee proposal. It will not reiterate the details of its evidence in this Argument, but addresses below the salient issues regarding Rider I that have emerged through the hearing of this matter.

4.3 Advantages of Rider I

4.3.1 Rider I would provide benefits to both TFOs and customers. Rider I would allow the TFO to invest in the CIAC assets, while providing the TFO with a return of and on its investment, based upon the TFO’s weighted average cost of capital (“WACC”). Rider I would also provide the option, at the TFO’s discretion, to convert the unamortized portion of existing CIAC amounts (“Legacy CIAC Assets”) to Rider I, thereby further expanding the TFO’s rate base through investment in these assets. This aspect of the Rider I proposal will be discussed in more detail below.

4.3.2 In addition, Rider I would give customers required to pay CIAC amounts the opportunity to make amortized payments over a specified period of time. Further, the Management Fee proposal will always be more costly than the status quo and, for customers who have a cost of

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\textsuperscript{16} Exhibit 110, Attachment AUC-TCE 1(b), page 3.
\textsuperscript{17} Transcript, page 1572, lines 14 through 21.
\textsuperscript{18} Transcript, page 1573, line 15 to page 1574, line 3.
\textsuperscript{19} Transcript, page 457, line 24 to page 458, line 7.
capital that is equal to or higher than the cost of capital of the TFO, the Management Fee proposal will also be more costly than Rider I.\textsuperscript{20} Exhibit 271, filed by TransCanada in this proceeding, demonstrated that where the cost of capital is equivalent, the Management Fee cost to the customer was 37 percent higher than either the status quo or under Rider I.

4.3.3 Finally, TransCanada submits that customers that are not affected by CIAC payments will be neutral or better off under the Rider I proposal as compared to the Management Fee proposal.\textsuperscript{21} Since Rider I payments will be made by the customer triggering the CIAC amount, Rider I will not impact other customers, subject to the minimal risk of default discussed below. This minimal risk must be measured against the certainty of an additional Management Fee payable each year, which may be borne by customers who did not trigger the contribution. Further, customers may also benefit from AltaLink’s improved credit metrics, as discussed below.

4.4 Default Risk

4.4.1 TransCanada recognizes that there is a risk of default associated with Rider I, as the repayment of the CIAC amount by the customer would occur over time. However, TransCanada submits that this risk of default would be minimal for the following reasons:

i. Rider I would only be available to parties that meet the AESO’s creditworthiness test.\textsuperscript{22}

ii. Under the Rider I Alternative, an initial CIAC payment from the customer during the construction period would still be required.\textsuperscript{23} TransCanada submits that the construction period is when the risk of default is greatest, as the interconnecting projects may not proceed. Only after the CIAC facilities are used and useful, would the customer be entitled to apply for Rider I. In this way, all Rider I payments, whether related to Legacy CIAC assets or not, would have the same accretive impact upon AltaLink’s credit metrics.

\textsuperscript{20} Exhibit 271; Exhibit 291, AML-TCE 1.
\textsuperscript{21} Exhibit 111, response to ASBG/PGA-TCE 8(a).
\textsuperscript{22} Exhibit 111, response to ASBG/PGA-TCE 3; Exhibit 94, page 4, lines 7 and 8.
\textsuperscript{23} Exhibit 94, page 4; Transcript, page 1500, lines 12 through 19.
iii. Default is also unlikely given the nature of the investment by the customer. DTS customers are either DISCOs or large industrials where electricity supply is a minority component of the overall cost structure.\textsuperscript{24} For STS customers, transmission costs also represent a small proportion of the cost of construction of the generation facility.\textsuperscript{25}

iv. In the unlikely event of default by these customers, it is probable that other parties would take over the interconnecting load or supply asset and would continue to require access to the grid.\textsuperscript{26} Upon taking over the interconnecting assets, the new owners would be required to either provide the unamortized payment up front or assume the Rider I payments if they qualified as creditworthy.\textsuperscript{27}

v. Finally, if the default, however unlikely, were to occur after some period of payments had been made and no party took over the interconnecting load or supply asset, the CIAC facilities could be salvaged for re-use or sale.\textsuperscript{28} These funds would further reduce the remaining un-recovered portion of payments under Rider I.

4.5 Conversion of Legacy CIAC Assets

4.5.1 During the hearing, concerns were raised regarding the conversion of Legacy CIAC Assets to Rider I, including AltaLink’s ability to raise capital for Legacy CIAC Assets and the impact such financing would have on AltaLink’s credit rating. TransCanada submits these concerns have been addressed for the following reasons.

4.5.2 The Rider I proposal would give both the TFO and AESO the discretion to determine whether or not Legacy CIAC Assets would be converted to Rider I.\textsuperscript{29} If a customer were to apply for a Rider I conversion of Legacy CIAC Assets, the AESO would first determine whether the

\textsuperscript{24} Exhibit 111, response to ASBG/PGA-TCE 3(a) and (b).
\textsuperscript{25} Ibid.
\textsuperscript{26} Exhibit 111, response to ASBG/PGA-TCE 3(b).
\textsuperscript{27} Transcript, page 1579, lines 2 through 10.
\textsuperscript{28} Exhibit 111, response to ASBG/PGA-TCE 3(b).
\textsuperscript{29} Exhibit 94, page 4, lines 15 through 17.
customer is creditworthy. If the customer was determined to be creditworthy, the TFO would then determine, in its sole discretion, whether it could raise the financing for the investment.30

4.5.3 If the TFO chose to invest in Legacy CIAC Assets, TransCanada submits that the TFO’s credit metrics would not be negatively impacted. In fact, as demonstrated in Exhibit 226 and testified to by AltaLink,31 the addition of Legacy CIAC Assets to its rate base would be accretive to AltaLink’s credit ratings because these assets are fully constructed and generate immediate cash flow. As discussed below, all Rider I payments, whether for future CIAC assets or Legacy CIAC Assets, would have the same accretive effect.

4.5.4 Finally, as raised in cross-examination by the Alberta Sugar Beet Growers Association and Potato Growers Association, TransCanada recognizes that a fairness issue may arise if the TFO determines it can only finance a portion of the requests that would otherwise qualify for conversion of Legacy CIAC Assets.32 TransCanada submits that mechanisms could be developed to deal with such situations to prevent undue discrimination, such as an apportionment or lottery system.33

4.6 Optionality of Rider I

4.6.1 Under TransCanada’s proposal, Rider I would not be mandatory. Rather, a customer could decide whether or not to apply for Rider I depending upon its own cost of capital and other factors.34 As a part of AltaLink’s rebuttal evidence, Dr. Cicchetti submitted a revised proposal that is aimed at the optionality of Rider I. His revised proposal would involve the implementation of Rider I, as well as the assignment of a Management Fee to specific customers who did not opt or qualify for Rider I.

4.6.2 TransCanada submits that Dr. Cicchetti’s revised proposal should not be accepted at this time. TransCanada expects that a significant number of customers will be interested in converting to

30 Transcript, page 1588, lines 15 through 25.
31 Transcript, page 476, line 11 to page 477, line 11.
32 Transcript, page 1522, lines 1 through 25.
33 Transcript, page 1523, lines 1 through 11.
34 Transcript, page 1588, lines 7 through 11.
Rider I. As demonstrated in Exhibit 271, the Rider I proposal is less costly for customers who have a cost of capital equal to or greater than the TFO’s and TransCanada would generally expect that a customer’s cost of capital will be higher than that of the TFO. Therefore, through a combination of Rider I and the other factors described in section 2.2, CIAC amounts relative to rate base should fall below and likely well below the “bright line” of 10 percent. TransCanada submits that the question of whether Rider I and the other factors identified in section 2.2 have adequately addressed the concerns regarding CIAC amounts relative to rate base could be examined in subsequent GTA proceedings of the AESO and TFOs. Dr. Cicchetti’s proposal could be reconsidered at that time should it be found to be necessary.

5.0 CONCLUSION

5.1 In summary, TransCanada submits that it has advanced compelling evidence that the Commission should deny AltaLink’s proposed Management Fee in its entirety at this time. The Management Fee is a costly and unnecessary method to resolve AltaLink’s concern regarding the lack of return on CIAC assets. Rider I is presently making its way through the AESO 2010 GTA consultation process and TransCanada anticipates that it will be included as part of the AESO’s 2010 GTA. Rider I will address the concerns of both TFOs and customers regarding CIAC assets by aligning investment with ownership and control. While there is a minimal credit risk associated with Rider I, TransCanada suggests that payments by customers that would be required in the event of default would be dwarfed by the extent of the annual payments required for the Management Fee. Given that Rider I is expected to be before the Commission in the near future, and that AltaLink will have the option to convert Legacy CIAC Assets, there is no need for immediate resolution of AltaLink’s concern. Further, there is evidence that suggests that the extent of the issue may be significantly reduced due to future capital expansions and other potential changes to the AESO tariff and the AESO contribution policy. TransCanada submits that the lack of return on CIAC assets that has caused both AltaLink and ATCO to apply for

35 Exhibit 291, AML-TCE 2.
36 Transcript, page 448, lines 7 through 22; page 1576, line 23 to page 1577, line 8.
Management Fees can and should be resolved on an industry-wide basis before this Commission at the AESO 2010 GTA.

Respectfully submitted.

Calgary, Alberta
June 15, 2009

TRANSCANADA ENERGY LTD.

Per: [Original signed by]
Nadine Berge
Senior Legal Counsel
Law & Regulatory Research
Dear Working Group Member:

Re: Meeting Agenda for Amortized Customer Contribution Option and Other Contribution Provisions Working Group

The first meeting of the Amortized Customer Contribution Option and Other Contribution Provisions Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 9:00 to 11:00 AM
- **Date:** Wednesday, June 10, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, and pastries

This working group includes the following members:
- AltaLink: Tony Demassi
- DUC: Dale Hildebrand
- FortisAlberta: John Holmes
- IPCAA: Vittoria Bellissimo
- NaturEner: Will Ingenthron
- TransCanada: Dan Levson or Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, David Michaud, and Shaun Andrews

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   - **Time:** 9:00 AM

2. **Review agenda**
   - **Time:** 9:10 AM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
     - **Time:** 9:15 AM
Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.

A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

## Background for customer contributions

### 9:20 AM

- Please review the enclosed information before the meeting, if possible:
  - (a) Discussion of customer contribution policy in section 8.1 (pages 91-99) and of AESO standard facilities in section 8.2 (pages 100-105) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  - (b) Recommendation 2 on standard facilities (pages 3-6) and recommendation 7 on customer contribution payment options (pages 10-11) from the customer contribution policy recommendations delivered from the AltaLink stakeholder consultation process, dated November 21, 2008
- Is there other background that participants consider particularly relevant?

## Amortized customer contribution payments

### 9:30 AM

- An amortized payment approach could be an alternative to the existing tariff provisions which require the customer contribution to be paid before construction (Article 9.2)
- Are there considerations for whether this approach applies to:
  - DTS (load) services,
  - STS (generation) services, or
  - both types of services?
- Should the approach be:
  - mandatory for all services in accordance with approved criteria, or
  - an option available at the choice of the customer?
- How should the risk of default be assessed, mitigated, and monitored under an amortized payment approach?
- What costs should be included under an amortized payment approach?
  - capital costs (depreciation)
  - return on equity
  - interest on debt
  - income tax
  - operation and maintenance expense
  - other expenses
- How should the term (number of years) for an amortized payment approach be established? What happens at the end of the term?

## Staged security requirements

### 10:30 AM

- Security requirements prior to payment of contribution could be staged to match costs incurred by the TFO
- How could the staging of security requirements be determined?
- What milestones exist for monitoring and adjusting staged security requirements?
7 Follow-up required for next meeting 10:45 AM
   • Summarize what tasks need to be completed before next meeting and who will complete them

8 Dates and times for next meeting(s) 10:55 AM

9 Adjourn 11:00 AM

This agenda and all other printed information related to the Amortized Customer Contribution Option and Other Contribution Provisions Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2471 or david.michaud@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: David Michaud, Manager, Regulatory, AESO
AEO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose
The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics
Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   • Substations included in POD cost data set
   • Inflation index to escalate POD cost data to 2010
   • Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   • Respond to AUC directions on analysis of TFO O&M costs
   • Determine if TFO O&M costs are energy-related
   • Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   • Methodology to analyze and assess design of operating reserve charge
   • Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   • Rate design principles for Fort Nelson and similar services
   • Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   • Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   • Rate design principles for higher-priority export and import services
   • Similarities and differences between domestic and intertie services
   • Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   • Rate design principles for deferral account riders
   • Practicality of improving allocation accuracy of deferral account riders
   • Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 **Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 **Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.

- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 **Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
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. 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.

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 Boards 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. 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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310 Tr. Vol. 6, pp. 1209-1210
311 Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13- 19
312 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.  

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 polices with those of the Discos and helps to preserve the

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313 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.314

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:

314 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;\textsuperscript{315}

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;\textsuperscript{316}

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;\textsuperscript{317}

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;\textsuperscript{318}

interconnection facility service characteristics and standards of functionality may change over time.\textsuperscript{319}

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.\textsuperscript{320}

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.

\textsuperscript{315} Decision 2005-096, p. 43
\textsuperscript{316} Decision 2005-096, p. 44
\textsuperscript{317} Decision 2005-096, p. 44
\textsuperscript{318} Decision 2005-096, p. 44
\textsuperscript{319} Decision 2005-096, p. 44
\textsuperscript{320} 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 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. 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.

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321 Ex. 007, pp. 28-29
322 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.
323 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).

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:

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.
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:

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

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,\(^ {325} \) 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.\(^ {326} \) 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.\(^ {327} \)

\(^{325}\) Tr. Vol. 2, p. 501, referenced at p. 64 of TCE Argument
\(^{326}\) Tr. Vol. 2, p. 502, referenced at p. 64 of TCE Argument
\(^{327}\) 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, 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 polices 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 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 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

328 Ex 223
329 Ex 223, pp. 3-11 (Updike 144 kV line and substation, and a potential connection of two oilsands developments)
330 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,\footnote{Ex. 347} 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.\footnote{Decision 2005-096, p. 73} 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)\footnote{Ex. 292} 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.
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.AEOS-003, the AESO provided hyperlinks to eight separate process guidelines related to distribution point of delivery interconnection process guidelines. These documents were prepared by the AESO with assistance from Alberta Discos and TFOs. 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.

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._ (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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334 Ex. 098
335 Ex. 098, AESO.AE-3, pp. 2-3, Tr 847
336 Ex. H-002, p. 1
337 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. 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.
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.\(^\text{339}\) 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.\(^\text{340}\)

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.\(^\text{341}\)

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\(^{339}\) Ex. 240, PPGA Transmission vs. Distribution evidence

\(^{340}\) AESO Reply Argument, pp. 35-36; Ex. 347 AESO Rebuttal Evidence pp. 11-15

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.\textsuperscript{342} 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.\textsuperscript{343}

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.

\textbf{8.3 Prepaid O&M Charge}

In the Application, the AESO described its proposed changes to Article 9.4 of its T&Cs.\textsuperscript{344} 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.\textsuperscript{345}

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

\textsuperscript{342} Ex. 098, AESO.AE-3, AESO Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service, section 4.3, pages 37-39
\textsuperscript{343} Ex. 098, AESO.AE-3, pages 2-3 of 4; Tr 847
\textsuperscript{344} Ex. 007, Application Section 6.5.2, pp. 13-15
\textsuperscript{345} Ex. 007, p. 14 of 47
customers to understand it and have confidence in it. This should reduce the amount of utility staff time required to explain it to customers and lower the number of customer complaints. This will also lead to lower requirement for AUC involvement.

It is the belief of the Working Group that common principles across TFOs, DFOs, and the AESO are beneficial to improving the Customer Contribution Policy and the Interconnection Process. The Working Group identifies that the “80/20 rule” is not a principle; it is simply one way of measuring, monitoring, or assessing if a particular contribution policy meets other principles of reasonableness, fairness, or intergenerational equity. The guiding principles are intended to identify that the current contribution policy does not establish an interconnection solution; it only established who pays for the solution when the payment is made. The Working Group believes that the adoption of the guiding principles will alleviate the concerns outlined.

2.0 Standard Facilities - Standards of Service

CONCERN

The current definition of “Standard Facilities” is “the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consists of a single radial transmission circuit and a single transformer to supply an individual point where electric energy is transferred between the customer’s facility and the Alberta Interconnected Electric System (“Point of Connection”).”

Interpretation of this definition, along with a number of other factors such as inflation, regulatory lag and the contribution formula design, has led to increased levels of customer contributions. In fact, other than small breaker addition projects, most customer interconnections have a customer contribution. In contrast, prior to 2005, customer contributions occurred on less than 20% of transmission interconnections.

The increase in customer contribution levels has resulted in dissatisfaction amongst TFO’s, DFO’s and interconnecting customers. In addition, the application of this definition focuses the planning effort on the least cost solution instead of the optimum long term solution.

RECOMMENDATION

1. Change the definition of Standard Facilities in the AESO tariff to “the most economical interconnection facilities which meet good utility practice including applicable reliability, protection, and operating criteria and standards”.

2. The AESO to lead a stakeholder process to establish Planning Principles and Standards of Service to guide application of the Contribution Policy.

The following draft Planning Principles and Standards of Service are a potential starting point for the Stakeholder Consultation. Utilities across Alberta may use different specific
standards due to evolution of their distribution/transmission network but the Planning Principles should be the same for each utility. These principles should help guide the development of the electric system as it evolves from minimum facilities supplying relatively small loads e.g.10 MVA, up to a major substation supplying loads over 100 MVA.

Planning Principles (draft)

2.1 **Target Restoration Times:** In the event of a contingency, power should be restored by the target restoration times as documented in Table 3.1-1 in the AESO’s “Distribution Point-of-Delivery Interconnection Process Guideline- Standards of Service”. If power cannot be restored by the targets, new facilities should be requested to allow the utility (i.e. TFO or DFO) to meet the target restoration times. Following are the target restoration times:

<table>
<thead>
<tr>
<th>Area</th>
<th>Guidelines for Target Restoration Times</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urban (population greater than 5000)</td>
<td>&lt; 1 hour</td>
</tr>
<tr>
<td>Rural (population less than 5000)</td>
<td>&lt; 4 hours</td>
</tr>
</tbody>
</table>

2.2 **Long Term Planning:** The following should be used to guide long term planning decisions:

a. Most electric utility facilities have a life of 25 years or greater and should be planned to be in service for at least 25 years.

b. A new facility should be added approximately 3 years before the capacity of an existing facility is expected to be exceeded to ensure facilities are in place before they are critical.

2.3 **Substation Location:** Substations should be located close to the load center to ensure appropriate levels of restoration and to minimize interruptions

2.4 **T&D Losses:** Facilities should be planned to minimize transmission and distribution losses.

2.5 **Motor Starting:** Electric facilities should be sized to ensure customer motors can start with up to three times inrush current. Customers should be able to start motors off the electric system and meet flicker limits with reasonable reduced voltage starting equipment up to 3 times inrush. If motor starting violates three times inrush, the customer is required to fund a cost effective solution such as a VFD.
2.6 **Reliability of Service**: When assessing the reliability of service to customers, the planner should consider:

c. Number of Customers affected,
d. Type of load (hospital, or oil and gas customers such as H2S safety concerns),
e. Density of load,
f. Social/economic/environmental impacts,
g. Time to repair, and
h. Time to restore service,

to ensure that the expected restoration times are less than the target restoration times as documented in Table 3.1-1 in the “AESO’s Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service”.

2.7 **Transmission vs. Combined Transmission/Distribution Service**: When the cost between two technically feasible interconnection alternatives is close (within plus or minus 10%), customers should be able to choose which of the two alternatives is the Standard Facility for contribution purposes.

2.8 **Cost, economics and schedule should be considered for any interconnection solution**

The following draft Standards of Service are proposed. A detailed explanation of these proposed standards is contained in Appendix A.1 – Standards of Service. *These standards are a guide only, recognizing that different TFO’s have different standards that have evolved over time and different operating practices.*

**Standards of Service (draft)**

<table>
<thead>
<tr>
<th>Load</th>
<th>Rural</th>
<th>Rural Area with Multiple Customers</th>
<th>Urban</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 15 MVA</td>
<td>One 138 KV line</td>
<td>N/A</td>
<td>Two 138 kV lines</td>
<td>One 138 KV line</td>
</tr>
<tr>
<td></td>
<td>One 15/20/25 MVA transformer</td>
<td>One 15/20/25 MVA transformer</td>
<td>One 15/20/25 MVA transformer</td>
<td></td>
</tr>
<tr>
<td>15 – 25 MVA</td>
<td>One 138 KV line</td>
<td>N/A</td>
<td>Two 138 kV lines</td>
<td>One 138 KV line</td>
</tr>
<tr>
<td></td>
<td>Two 15/20/25 MVA transformers</td>
<td>Two 15/20/25 MVA transformers</td>
<td>Two 15/20/25 MVA transformers</td>
<td></td>
</tr>
<tr>
<td>25 – 42 MVA</td>
<td>Two 138 KV lines</td>
<td>N/A</td>
<td>Two 138 kV line</td>
<td>Two 138 kV lines</td>
</tr>
<tr>
<td></td>
<td>Two 25/33/42 MVA transformers</td>
<td>Two 25/33/42 MVA transformers</td>
<td>Two 25/33/42 MVA transformers</td>
<td></td>
</tr>
<tr>
<td>42 – 83 MVA</td>
<td>N/A</td>
<td>Two 138 kV lines</td>
<td>Two 138 kV lines</td>
<td>Two 138 kV lines</td>
</tr>
<tr>
<td></td>
<td>Two 50/67/83 MVA transformers</td>
<td>Two 50/67/83 MVA transformers</td>
<td>Two 50/67/83 MVA transformers</td>
<td></td>
</tr>
</tbody>
</table>
83 – 167 MVA | N/A | Two 240 kV lines | Two 240 kV lines | Two 240 kV lines |
| Two 100/138/167 MVA transformers | Two 100/138/167 MVA transformers | Two 100/138/167 MVA transformers |
| 240 kV /25 kV | 2 transformers | 2 transformers | 2 transformers | 2 transformers |
| Motor Starting | 3 x Inrush | 3 x Inrush | 3 x Inrush | 3 x Inrush |

**KEY BENEFITS & IMPACTS**

Adoption of the recommended definition change, Planning Principles and Standards of Service are expected to provide the following benefits:

- Provides a clear and transparent approach to application of the contribution policy.
- Assists the AESO with planning for the long term rather than one interconnection at a time.
- Facilitates better decisions when planning for an area (rural or urban) that includes a combination of distribution and transmission.
- Provides DFOs, TFOs and industrials with substations that meet pre-defined levels of reliability.
- Minimizes debate between the AESO and customers regarding application of the contribution policy.
- Increases customer satisfaction.
- Eliminates rework at existing substations because long term planning implications will have been considered.

**3.0 Early System Rebuilds**

The AESO should consider the following principles when finalizing the rebuild and salvage policy:

3.1 The allocation of capital costs to the account of customer or system will be fair to existing and new customers.
6.1 Define reasonable book-end key activities within a project wherein either a former approved or a current approved Customer Contribution Policy would apply to a project. If there is a change in the approved Customer Contribution Policies between the point at time at which the customer receives their first proposal from the AESO for service, and the point in time at which the customer executes their final contract for service (which typically occurs a month or two prior to energization), then the customer is given a choice which Customer Contribution Policy should apply.

6.2 Include a procedure for updating “standard facilities” estimates to accurately reflect the conditions that are impacting the actual project, and would impact the standard facilities project if it were being constructed. A pro-rata adjustment based on the amount that the actual project costs have increased, or decreased from the estimate would be appropriate.

The working group believes that the movement from a hard date to a window for migration from one policy to another should eliminate pressure on AESO and TFO processes to get to a particular point in a project by a particular timeline in order to accommodate a shift in policy. This transition provides customers with some degree of certainty that a proposal that they are reviewing and accepting in relation to a project is the worst-case from a Customer Contribution Policy perspective. It provides assurance that the costs on which a customer’s commercial terms are based on are being adjusted to reflect current market conditions and provides fairness and certainty. Finally, putting an adjustment process in place would ensure consistency of application across all projects.

7.0 Customer Contribution Payment Options

A concern regarding customer contribution payment options was identified by the Working Group. Through this period of rapid and large scale expansion of the Alberta transmission system, the majority of direct connect projects are requiring very large up front customer contributions for facilities the customers don’t own and operate. This also results in the TFO owning and operating facilities being used to provide service that they are not earning a return on, while still incurring operational, ownership, integration and prudency risk, the same as any other asset.

In these situations, resulting in large customer contributions, customers are financing utility owned/operated assets, for which they have no control or management of, nor do they assume any risk.

The Working Group recommends that the AESO Investment Policy should include an option for the contribution to be set up as an AESO tariff payment determined by the TFO cost of service method including income tax, applied over the DTS/STS contract term. The contribution structured as an AESO tariff payment would be made available to any creditworthy customer. The attractiveness of the AESO Tariff Option to the customer will depend on the customers IRR and other factors including the customer’s election for treatment of the transaction on their balance sheet. The customer/POD
specific AESO tariff Payment Option, or what has been referred to as a Facilities Charge Agreement, is not a new concept and has been applied successfully to specific PODs in the past. The adoption of the aforementioned eliminates the need for customer to deploy large amounts of capital for facilities they will not own and operate.

8.0 Load First Contribution Policy

The Working Group identified a concern that investment for dual use-customers is reduced by the customer’s substation ratio\(^5\) with a corresponding reduction in the DTS tariff. The Working Group believes that some customers may want a higher investment amount, and be willing to pay the standard tariff rates over time.

The Working Group recommends that for a new or expanded POD a customer can elect to be “load first” and have the full DTS contract capacity increase applied to the DTS rate, the Primary Service Credit and the investment policy, regardless if there is a corresponding increase in STS contract capacity. In this case the “deemed” substation ratio will be 100%, and will not be the same as the DTS/(STS+DTS) contract capacity ratio (the “real” substation ratio)

The benefits of adoption of this recommendation include greater customer choice to determine an appropriate level of system investment. This may dissuade some customers from building customer owned substations, and this would allow for the optimization of a comprehensive and more readily integrated system.

Conclusion

The Working Group recognizes that the downward pressure on customer contributions causes upward pressure on the rates. In summary, the Working Group believes that the recommendations maintain the postage stamp philosophy, while promoting equitable treatment among customers, DFOs, and TFOs. In addition, the recommendations will help align long term transmission planning with good utility practices, improve flexibility for customers, and improve cycle times through improved clarity, transparency, and consistency.

\(^5\) DTS contract capacity/ (DTS+STS contract capacity)
June 10, 2009

Tariff Provisions Related to Customer-Owned Substations Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Tariff Provisions Related to Customer-Owned Substations Working Group

The first meeting of the Tariff Provisions Related to Customer-Owned Substations Working Group for the AESO’s 2010 tariff application is scheduled as follows:

Time: 11:30 AM to 1:30 PM
Date: Thursday, June 11, 2009
Location: Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
Refreshments: Working lunch and beverages

This working group includes the following members:
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- StatoilHydro: Brian Blattler
- TransCanada: Dan Levson
- UCA: Ed de Palezieux
- AESO: John Martin and Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions** 11:30 AM
   - Please indicate which stakeholders you represent

2. **Review agenda** 11:40 AM

3. **Review draft working groups terms of reference** 11:45 AM
   - See enclosed document originally posted on April 22, 2009
• The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
  – Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
  – A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.
• Identify any concerns with or additional revisions to the terms of reference
• Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for customer-owned substations
• Please review the enclosed information before the meeting, if possible:
  (a) Discussion of primary service credit in section 5.10 (pages 63-68) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (b) AESO’s responses to Directions 10 and 11 in its 2007 General Tariff Application Refiling, filed on February 1, 2008
• Is there other background that participants consider particularly relevant?

5 Tariff principles for customer-owned substations
• What principles were established in Decision 2007-106 or in other decisions?
• Have conditions changed or is new information available such that those principles no longer apply?
• Are there additional principles that should be added?

6 Additional considerations for customer-owned substations
• What additional concerns exist for customer-owned substations?
• Are there other approaches to addressing these concerns?

7 Follow-up required for next meeting
• Summarize what tasks need to be completed before next meeting and who will complete them

8 Dates and times for next meeting(s)

9 Adjourn

This agenda and all other printed information related to the Tariff Provisions Related to Customer-Owned Substations Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AESCO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
   - Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

### 3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

### 4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

### 5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
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.

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.

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, 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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202 Ex. 064
203 Decision 2005-096, p. 38
204 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

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%.\textsuperscript{206}

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).\textsuperscript{207} 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.\textsuperscript{208}

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.\textsuperscript{209} 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.\textsuperscript{210} 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.\textsuperscript{211}

\textsuperscript{205} Ex. 005, Application, Section 4, p. 51
\textsuperscript{206} Ex. 005, Application, Section 4, p. 51
\textsuperscript{207} Ex. 229, DUC Evidence, pp. 34-36 and Figure 19
\textsuperscript{208} Ex. 229, DUC Evidence, pp. 14-17
\textsuperscript{209} AESO Argument, p. 62
\textsuperscript{210} TCE Argument, p. 61-62
\textsuperscript{211} 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.\textsuperscript{212}

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.\textsuperscript{213}

DUC disagreed with the AESO’s suggestion that there may be some radial lines costs that are higher for larger PODs\textsuperscript{214} 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.\textsuperscript{215}

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.

\begin{footnotesize}
\begin{enumerate}
\item \textsuperscript{212} AESO Argument, p. 62, l. 39 – p. 40, l. 2
\item \textsuperscript{213} DUC Reply, p. 9
\item \textsuperscript{214} AESO Argument, p. 36, l. 29-39
\item \textsuperscript{215} Ex. 126, TCE.AESO-025
\end{enumerate}
\end{footnotesize}
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. 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.

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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216 See Section 5.7.4, refers to CG.DUC-1(c) and DUC Evidence (Ex. 229), pp. 13-16
217 Ex. 005, Application, Section 4, p. 52
Customer Choice Regulation,\textsuperscript{218} 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.\textsuperscript{219}

DUC disagreed with the AESO that isolated generating units should be eligible for the PSC. DUC noted in its evidence\textsuperscript{220} 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.\textsuperscript{221}

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,\textsuperscript{222} well in excess of the estimated DTS revenue of the $160,000 per year the AESO receives from each of these sites.\textsuperscript{223}

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.\textsuperscript{224}

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

\textsuperscript{218} Alberta Regulation 165/2003, as amended
\textsuperscript{219} Ex. 005, Application, Section 4, p. 52 and p. 20
\textsuperscript{220} Ex. 229, DUC Evidence, p. 38
\textsuperscript{221} 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)
\textsuperscript{222} 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.
\textsuperscript{223} DUC POD PSC Evidence CG 17 Expanded.xls, tab CG-017 (b-c) PSC Details p2, cells M8:R22
\textsuperscript{224} 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 insolated 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, 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. 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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225 Ex. 229, p. 38, lines 21 to 25
226 Ex. 005, p. 52
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:

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>DTS Charge</th>
<th>Primary Service Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Amount</td>
<td>%</td>
</tr>
<tr>
<td>Billing Capacity Charge ≤7.5 MW</td>
<td>$3,090.00/MW</td>
<td>55%</td>
</tr>
<tr>
<td>Bill Cap Charge &gt;7.5 to ≤17 MW</td>
<td>$1,069.00/MW</td>
<td>55%</td>
</tr>
<tr>
<td>Bill Cap Charge &gt;17 to ≤40 MW</td>
<td>$627.00/MW</td>
<td>55%</td>
</tr>
<tr>
<td>Billing Capacity Charge &gt;40 MW</td>
<td>$332.00/MW</td>
<td>100%</td>
</tr>
<tr>
<td>Customer Charge</td>
<td>$5,493.00/month</td>
<td>55%</td>
</tr>
</tbody>
</table>

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:

<table>
<thead>
<tr>
<th>Investment Function Component</th>
<th>DTS Investment</th>
<th>PSC Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Amount</td>
<td>%</td>
</tr>
<tr>
<td>Fixed</td>
<td>$51,400/year</td>
<td>45%</td>
</tr>
<tr>
<td>First 7.5 MW of Contract Capacity</td>
<td>$28,900/MW/year</td>
<td>45%</td>
</tr>
<tr>
<td>Next 9.5 MW of Contract Capacity</td>
<td>$10,000/MW/year</td>
<td>45%</td>
</tr>
<tr>
<td>Next 23 MW of Contract Capacity</td>
<td>$5,900/MW/year</td>
<td>45%</td>
</tr>
<tr>
<td>All Remaining Contract Capacity</td>
<td>$3,100/MW/year</td>
<td>0%</td>
</tr>
</tbody>
</table>

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.
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.
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
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Tariff Changes Related to Transition of Authoritative Documents (TOAD)
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Amortized Customer Contribution Option and Other Contribution Provisions
- Potential changes to AESO standard facilities definition
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Tariff Provisions Related to Customer-Owned Substations
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- A company or association may generally have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation.
The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.

(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.
(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.

(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
May 28, 2009

AESO 2010 Tariff Consultation Working Groups Participants
AESO Stakeholders

Dear Stakeholder:

Re:  Additions to Final Participant List and First Meetings for AESO 2010 Tariff Consultation Working Groups

On May 21, 2009, the AESO posted its final participant list for working groups in consultation for its 2010 tariff application. The AESO had worked with participants to reduce working group size to a maximum of six stakeholder members while ensuring diversity and balanced representation on the groups.

Some stakeholders subsequently expressed concerns about representation on two working groups, specifically those for:
- Export and Import Rates XTS and ITS and

The AESO notes that those two groups attracted greater interest than any other and perhaps generate a greater diversity of interests. After further consideration, the AESO has decided to add one more stakeholder member to each of those groups. The updated final participants on each working group are provided below.

As well, the first meeting for each working group has now been scheduled, as indicated for each group. Meeting agendas will be distributed to working group members and posted on the AESO website prior to each meeting. Dates for subsequent meetings will be established during the first meetings.

(a) **POD Cost Function and Investment Level Update**
First Meeting: Friday, May 29, 2009, 9:00 – 10:30 AM, AESO Meeting Room 2539
- AltaLink: Dean Fischbach
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- TransCanada: Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma
(b) **TFO O&M Cost Causation Study**
First Meeting: Monday, May 25, 2009, 1:00 – 3:00 PM, AESO Meeting Room 2506
- AltaLink: James Yeo
- ENMAX: Penny Haldane
- EPCOR: Stan Yee
- StatoilHydro: Brian Blattler
- UCA: Rick Cowburn
- AESO: John Martin, David Michaud
- Consultant to AESO: Arnie Reimer

(c) **DTS Operating Reserve Charge Design**
First Meeting: Friday, June 5, 2009, 1:00 – 3:00 PM, AESO Meeting Room 2538
- ADC: Colette Kearl
- AltaLink: Hao Liu
- ENMAX: Randy Stubbings
- IPCAA: Vittoria Bellissimo
- TransCanada: Vince Kostesky
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma

(d) **Fort Nelson Rate FTS**
First Meeting: Monday, June 1, 2009, 2:00 – 4:00 PM, AESO Meeting Room 2538
- AltaLink: Hao Liu
- BC Hydro: John Rich, Yvette Maiangowi, Fred James, Lewis Manning
- Harvest: Dale Hildebrand
- IPCAA: Sheldon Fulton
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

(e) **Export and Import Rates XTS and ITS**
First Meeting: Tuesday, June 2, 2009, 11:00 AM – 1:00 PM, AESO Meeting Room 2506
- ATCO Power: Kim Johnston
- IPCAA: Vittoria Bellissimo
- MATL: Bob Williams, Paul Kos
- NaturEner: Juliane Kniebel-Huebner
- Powerex: Lisa Cherkas
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma, Gordon Nadeau

(f) **Deferral Account Riders B and C**
First Meeting: Monday, June 8, 2009, 10:00 AM – 12:00 PM, AESO Meeting Room 2506
- ADC: Colette Kearl
- ATCO Electric: Nick Palladino
- EPCOR: Stan Yee
- FortisAlberta: Monica Huynh
- IPCAA: Vittoria Bellissimo
- UCA: Rick Cowburn
- AESO: John Martin, Carol Moline
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
First Meeting: Tuesday, June 9, 2009, 11:00 AM – 1:00 PM, AESO Meeting Room 2506
- AltaLink: Cayla Saby
- ATCO Power: Kim Johnston
- ENMAX: Penny Haldane
- EPCOR: Lynn Meyer
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin
- Consultant to AESO: Evelyn Kelly

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
First Meeting: Wednesday, June 10, 2009, 9:00 – 11:00 AM, AESO Meeting Room 2506
- AltaLink: Tony Demassi
- DUC: Dale Hildebrand
- FortisAlberta: John Holmes
- IPCAA: Vittoria Bellissimo
- NaturEner: Will Ingenthron
- TransCanada: Dan Levenson, Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, David Michaud, Shaun Andrews

(i) **Tariff Provisions Related to Customer-Owned Substations**
First Meeting: Thursday, June 11, 2009, 11:30 AM – 1:30 PM, AESO Meeting Room 2506
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- StatoilHydro: Brian Blattler
- TransCanada: Dan Levenson
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

All information related to the AESO’s 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff → Current Consultations → 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
May 21, 2009

AESO 2010 Tariff Consultation Working Groups Participants
AESO Stakeholders

Dear Stakeholder:

Re: Final Participant List for AESO 2010 Tariff Consultation Working Groups

On April 30, 2009, the AESO posted the first round participant list for working groups in consultation for its 2010 tariff application. Stakeholders were invited to consider whether to participate on additional working groups or to request removal from one or more working groups, to balance their participation among the groups and to avoid unnecessaryduplication of interests.

The AESO had initially intended to limit working groups to a maximum of four stakeholder members. In light of the large amount of interest in some working groups, the AESO has increased that maximum to six stakeholder members. The AESO has worked with participants to reduce working group size to the new maximum while ensuring diversity and balanced representation on the groups.

The final participants on each working group, including AESO representatives, are provided below. Ghaz Marinho of the AESO will be contacting participants to set up the first meeting for each working group in the next few days.

(a) POD Cost Function and Investment Level Update
- AltaLink: Dean Fischbach
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- TransCanada: Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

(b) TFO O&M Cost Causation Study
- AltaLink: James Yeo
- ENMAX: Penny Haldane
- EPCOR: Stan Yee
- StatoilHydro: Brian Blattler
- UCA: Rick Cowburn
- AESO: John Martin, David Michaud
- Consultant to AESO: Arnie Reimer
(c) **DTS Operating Reserve Charge Design**
- ADC: Colette Kearl
- AltaLink: Hao Liu
- ENMAX: Randy Stubbings
- IPCAA: Vittoria Bellissimo
- TransCanada: Vince Kostesky
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma

(d) **Fort Nelson Rate FTS**
- AltaLink: Hao Liu
- BC Hydro: John Rich, Yvette Maiangowi, Fred James, Lewis Manning
- Harvest: Dale Hildebrand
- IPCAA: Sheldon Fulton
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

(e) **Export and Import Rates XTS and ITS**
- ATCO Power: Kim Johnston
- IPCAA: Vittoria Bellissimo
- MATL: Bob Williams, Paul Kos
- NaturEner: Juliane Kniebel-Huebner
- Powerex: Lisa Cherkas
- TransCanada: Chris Best
- AESO: John Martin, Raj Sharma, Gordon Nadeau

(f) **Deferral Account Riders B and C**
- ADC: Colette Kearl
- ATCO Electric: Nick Palladino
- EPCOR: Stan Yee
- FortisAlberta: Monica Huynh
- IPCAA: Vittoria Bellissimo
- UCA: Rick Cowburn
- AESO: John Martin, Carol Moline

(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- AltaLink: Cayla Saby
- ATCO Power: Kim Johnston
- ENMAX: Penny Haldane
- EPCOR: Lynn Meyer
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin
- Consultant to AESO: Evelyn Kelly
Amortized Customer Contribution Option and Other Contribution Provisions

- AltaLink: Tony Demassi
- FortisAlberta: John Holmes
- IPCAA: Vittoria Bellissimo
- NaturEner: Will Ingenthorn
- TransCanada: Dan Levson, Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, David Michaud, Shaun Andrews

Tariff Provisions Related to Customer-Owned Substations

- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- StatoilHydro: Brian Blattler
- TransCanada: Dan Levson
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

If you were interested in participating on a working group but could not be accommodated due to maximum size limits, the AESO encourages you to contact one of the working group members to ensure your views are represented on the relevant working group. Working group information will be posted on the AESO website, and stakeholders are also encouraged to monitor that information and to contact the AESO or one of the working group members if they wish to provide input on a matter being discussed in a working group.

All stakeholders will also have opportunity to participate in the remainder of the tariff consultation process through discussion papers and requests for comments as well as general stakeholder presentations. The AESO encourages stakeholders to take part in these more general forums.

The schedules and agendas for the first working group meetings will be posted on the AESO’s website and distributed to working group participants as soon as dates and times can be confirmed. As noted in the draft terms of reference, working group members may participate in meetings by conference call.

The AESO plans to review the draft working groups terms of reference at the first meeting of each working group. The terms of reference will be finalized and posted after the initial meetings.

All information related to the AESO’s 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ➤ Current Consultation ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
    Raj Sharma, Senior Tariff Analyst, AESO
    David Michaud, Manager, Regulatory, AESO
    Arnie Reimer, TFO O&M Study, Consultant to AESO
    Gordon Nadeau, Market Design Specialist, AESO
    Carol Moline, Director, Accounting & Treasury, AESO
    Evelyn Kelly, TOAD Project Manager, Consultant to AESO
    Shaun Andrews, Account Manager, Customer Interconnections, AESO
    Ghaz Marinho, Administrative Assistant, AESO
April 30, 2009

AEO 2010 Tariff Consultation Working Groups Participants
AEO Stakeholders

Dear Stakeholder:

Re: First Round Participant List for AESO 2010 Tariff Consultation Working Groups

On April 22, 2009, the AESO posted an invitation for stakeholders to participate on working groups in consultation for its 2010 tariff application, including draft terms of reference and a form for comments on both the terms of reference and the consultation process.

As explained in the invitation, a two-round signup process will be used to establish participation on the working groups. In the first round, stakeholders indicated their interest in participating on the working groups as listed below. Seventeen stakeholders have indicated interest in participating, to date:

- Alberta Direct Connect Consumers Association (“ADC”),
- AltaLink Management Ltd. (“AltaLink”),
- ATCO Electric,
- ATCO Power,
- BC Hydro,
- Dual Use Customers (“DUC”),
- ENMAX,
- EPCOR,
- FortisAlberta Inc. (“FortisAlberta”),
- Harvest Operations Corp. (“Harvest”),
- Industrial Power Consumers Association of Alberta (“IPCAA”),
- NaturEner,
- NorthPoint Energy Solutions (“NorthPoint”, a subsidiary of SaskPower),
- Powerex Corp. (“Powerex”, a subsidiary of BC Hydro),
- StatoilHydro Canada Ltd. (“StatoilHydro”),
- TransCanada, and
- Utilities Consumer Advocate (“UCA”).

For the second round, stakeholders should review the initial participation list and consider whether to participate on additional working groups or to request removal from one or more working groups, to balance their participation among the groups and to avoid unnecessary duplication of interests. Given the large amount of interest in some working groups, the AESO will also work with participants to reduce working group size to the suggested maximum of four to six members while ensuring diversity and balanced representation on the groups. Changes to
working group participation should be requested either by sending a revised participation form or a list of changes by **Tuesday, May 5, 2009**, to April Walters at april.walters@aeso.ca.

Some stakeholders have advised the AESO they were unable to confirm their participation by the first round response deadline. In such cases, stakeholders are encouraged to indicate their interest in participating on the working groups as part of the second round.

A final participant list will be posted by the AESO on Wednesday, May 6, 2009, and will also be distributed by email to participants.

1 **Working Groups on Which Stakeholders Are Interested in Participating**

(a) **POD Cost Function and Investment Level Update**
   - AltaLink: Dean Fischbach
   - ATCO Electric: Ken Koenig
   - DUC: Dale Hildebrand
   - ENMAX: Andy Morgans
   - IPCAA: Sheldon Fulton
   - TransCanada: Vince Kostesky
   - UCA: Ed de Palezieux

(b) **TFO O&M Cost Causation Study**
   - AltaLink: James Yeo
   - ENMAX: Penny Haldane
   - EPCOR: Stan Yee
   - StatoilHydro: Brian Blattler
   - UCA: Rick Cowburn

(c) **DTS Operating Reserve Charge Design**
   - ADC: Colette Kearl
   - AltaLink: Hao Liu
   - ENMAX: Randy Stubbings
   - IPCAA: Vittoria Bellissimo
   - TransCanada: Vince Kostesky
   - UCA: Rick Cowburn

(d) **Fort Nelson Rate FTS**
   - AltaLink: Hao Liu
   - BC Hydro: John Rich, Yvette Maiangowi, Fred James, Lewis Manning
   - Harvest: Dale Hildebrand
   - IPCAA: Sheldon Fulton
   - Powerex: Lisa Cherkas
   - UCA: Ed de Palezieux

(e) **Export and Import Rates XTS and ITS**
   - AltaLink: Hao Liu
   - ATCO Power: Kim Johnston
   - ENMAX: Randy Stubbings
   - IPCAA: Vittoria Bellissimo
The AESO is currently scheduling initial meetings for the working groups. The meeting schedule will be posted on the AESO’s website and distributed to working group participants within a few days.

The AESO has also attached to this letter its responses to comments provided by participants on the draft terms of reference for the 2010 Tariff Consultation Working Groups and on the

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- NaturEner: Juliane Kniebel-Huebner
- NorthPoint: Dennis Slade
- Powerex: Lisa Cherkes
- TransCanada: Dan Levson
- UCA: Rick Cowburn

(f) **Deferral Account Riders B and C**
   - ADC: Colette Kearl
   - ATCO Electric: Nick Palladino
   - EPCOR: Stan Yee
   - FortisAlberta: Monica Huynh
   - IPCAA: Vittoria Bellissimo
   - UCA: Rick Cowburn

(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
   - AltaLink: Cayla Saby
   - ATCO Power: Kim Johnston
   - ENMAX: Penny Haldane
   - EPCOR: Lynn Meyer
   - TransCanada: Chris Best
   - UCA: Rick Cowburn

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
   - AltaLink: Tony Demassi
   - ATCO Electric: Mike Gillis
   - DUC: Dale Hildebrand
   - ENMAX: Andy Morgans
   - FortisAlberta: John Holmes
   - IPCAA: Vittoria Bellissimo
   - NaturEner: Will Ingenthron
   - StatoilHydro: Brian Blattler
   - TransCanada: Dan Levson
   - UCA: Ed de Palezieux

(i) **Tariff Provisions Related to Customer-Owned Substations**
   - ATCO Electric: David Leew
   - DUC: Dale Hildebrand
   - ENMAX: Andy Morgans
   - IPCAA: Sheldon Fulton
   - StatoilHydro: Brian Blattler
   - TransCanada: Dan Levson
   - UCA: Ed de Palezieux
consultation process. Stakeholders are invited to provide additional comments as part of this second round stage using the original Stakeholder Signup and Comment Form.

The Stakeholder Signup and Comment Form and other information related to the AESO’s 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultation ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

attachment

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
    Raj Sharma, Senior Tariff Analyst, AESO
    April Walters, Executive Assistant, AESO
### AESO 2010 Tariff Consultation Working Groups

#### April 22, 2009 Invitation — Stakeholder Comments and AESO Responses

<table>
<thead>
<tr>
<th>Stakeholder Comment</th>
<th>AESO Response</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2 Comments on Draft Working Groups Terms of Reference</strong></td>
<td></td>
</tr>
<tr>
<td><strong>IPCAA</strong></td>
<td>It is assumed that Working Groups will further scope out their Terms of Reference once formed.</td>
</tr>
<tr>
<td></td>
<td>Yes, the AESO expects Working Groups will develop and revise the Terms of Reference, where appropriate. In particular, as noted in section 2 of the draft Terms of Reference, Working Groups are expected to determine what issues they will examine.</td>
</tr>
<tr>
<td><strong>IPCAA</strong></td>
<td>Timelines are adequate so as not to drag out the process too long. Meetings every 2 weeks might get to be onerous due to the travel involved. Is it possible to attend meetings via a conference call?</td>
</tr>
<tr>
<td></td>
<td>Yes, as noted in section 5(a) of the draft Terms of Reference, Working Group members may participate in meetings via conference call.</td>
</tr>
</tbody>
</table>

| **3 Comments on Proposed Working Group Consultation Process** | |
| **IPCAA** | It is vital that any documentation prepared by, or available to the Working Group members is also made available to other AESO stakeholders; |
| | The AESO intends to post on its website all written documentation available to or prepared by the Working Groups. |
| | It may not be practical for Working Groups to prepare and release recommendation or issue papers. However, the AESO expects to include Working Group recommendations and issues are expected in discussion papers prepared by the AESO. |
| **IPCAA** | If no formal minutes are to be taken, Working Groups should release recommendations papers (or issues papers if no recommendations can be reached) upon concluding the consultation sessions. |
| **NorthPoint** | Seems like a good way to get a group of stakeholders to focus on a few particular topics in the tariff instead of general requests for comments on the entire application. |
| **Additional Comments** | |
| **NorthPoint** | Although I am not an expert on this topic, I have been following what the AESO has been doing in regards to this topic with past tariff applications and am familiar with what the practice is in other jurisdictions. |
| **UCA** | Initial proposal for participation from the UCA. |
April 22, 2009

AESO Stakeholders

Dear Stakeholder:

Re: Invitation to Participate on Working Groups in Consultation for AESO 2010 Tariff Application

In the stakeholder consultation meeting on the AESO’s 2010 tariff application held on April 15, 2009, the AESO discussed the formation of several small working groups to explore specific topics for its 2010 tariff application. This letter provides additional information on those working groups, including draft terms of reference, and invites stakeholders to participate on them.

At the April 15 meeting, stakeholders suggested a two-round signup process to establish participation on the working groups. The AESO proposes the following process.

1. In the first round, stakeholders are requested to indicate on the enclosed sign-up form the working groups on which they are interested in participating. Completed forms are to be returned by Wednesday, April 29, 2009, to April Walters at april.walters@aeso.ca.

2. The AESO will post the list of first-round working group participants on its website on Thursday, April 30, 2009, and will also distribute the list by email to those who signed up.

3. In the second round, stakeholders can ask to participate on additional working groups or to be removed from one or more working groups that they had signed up for in the first round. This will allow stakeholders to balance their participation among the working groups, and avoid duplication on groups where their interest may already be adequately represented. The AESO may also suggest changes during the second round to ensure diversity and balanced representation of views on working groups. Requests for second-round changes should be provided by Tuesday, May 5, 2009, to April Walters at april.walters@aeso.ca.

4. The AESO will post the final list of working group participants on its website on Wednesday, May 6, 2009, and will also distribute the list by email to participants.

The AESO will schedule initial meetings for the working groups to begin Thursday, May 7, 2009. Details for these initial working group meetings are expected to be provided when the first-round working group list is posted on April 30.

The AESO has also attached to this letter draft terms of reference for the 2010 Tariff Consultation Working Groups. The AESO suggests these terms of reference be used to guide the activities of the working groups. The AESO invites stakeholders to provide comments on the
draft terms of reference and on the proposed working group consultation process, in the space provided on the enclosed signup form.

Information related to the AESO’s 2010 tariff consultation is available on the AESO’s website at www.aeso.ca by following the path Tariff ▶ Current Consultation ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

attachment
enclosure

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
    Raj Sharma, Senior Tariff Analyst, AESO
    April Walters, Executive Assistant, AESO
AEO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AEO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AEO on specific topics for the AEO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AEO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AEO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
   - Possible integration of Riders B and C
(g) Tariff Changes Related to Transition of Authoritative Documents (TOAD)
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) Amortized Customer Contribution Option and Other Contribution Provisions
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) Tariff Provisions Related to Customer-Owned Substations
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.
(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.

(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
In the stakeholder consultation meeting on the AESO’s 2010 tariff application held on April 15, 2009, the AESO discussed the formation of several small working groups to explore specific topics for its 2010 tariff application. The AESO provided further information on the working groups, draft terms of reference, and a two-round signup process to establish participation, in a letter dated April 22, 2009. Stakeholders are invited to indicate below the working groups on which they are interested in participating and to provide comments on the draft terms of reference and the proposed working group consultation process. Completed forms should be returned by Wednesday, April 29, 2009, to April Walters at april.walters@aeso.ca.

<table>
<thead>
<tr>
<th>Working Groups on Which Stakeholder Is Interested in Participating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contact Details for Stakeholder Representative on Working Group(s) Marked at Right</td>
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<td>POD Cost Function and Investment Level Update</td>
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<tr>
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<th>Comments on Proposed Working Group Consultation Process</th>
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<table>
<thead>
<tr>
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<th>Additional Comments</th>
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</tbody>
</table>

Please return this form with your comments by April 29, 2009, to:

April Walters  
Executive Assistant, Regulatory  
Email: april.walters@aeso.ca  
Phone: 403-539-2465  
Fax: 403-539-2524
AESO 2010 Tariff Stakeholder Consultation

John Martin, Lee Ann Kerr, and Raj Sharma
AESO Regulatory
June 24, 2009 — Calgary

Agenda

• Introduction (slides 1-5)
• Studies
  – POD cost function update (slides 6-12)
  – TFO O&M cost causation study (slides 13-17)
  – Operating reserve charge investigation (slides 18-22)
• 2010 rate proposals (slides 23-42)

Break

• 2010 terms and conditions proposals (slides 43-71)
• Next steps (slides 72-75)
Recent Applications

- AESO 2009 Rates Update
  - Filed March 12, 2009
  - Responses to information requests due this Friday, June 26
  - New rates may be effective October 1, 2009
- AESO 2008 Deferral Account Reconciliation
  - Filed April 9, 2009
  - Interim approval to recover $6.4 million net shortfall on May 2009 statements of accounts to be settled at end of June 2009
  - Responses to information requests due Monday, July 13
  - Final decision expected in late fall 2009

AESO 2010 Tariff Application

- Plan to file in late September 2009
- Working group meetings being held from May to July 2009
  - Working group information posted on AESO website
  - Parties should contact working group members to discuss progress
- 2010 tariff will build on existing tariff
  - Changes to rates include hourly DTS operating reserve charge and potential additional export and import rates
  - Changes to terms and conditions include revision to contribution policy and revisions to align and consolidate information
- Discussion documents and comment processes to review proposed changes
Meeting Objectives

- Understanding of preliminary results of studies being prepared for tariff application
- Understanding of preliminary proposals for tariff changes
- Establish expectations for remainder of consultation process and for filing of application
- Proposals are discussed “without prejudice” and may not be included or may be different in tariff application when filed
- Please ask questions during presentation

POD Cost Function Update

Raj Sharma
Senior Tariff Analyst, AESO Regulatory
**Updated “Greenfield” Data Set**

- 48 load-only interconnection projects included in POD cost function in 2007 tariff proceeding
  - From 1987 to 2006
  - Escalated to 2007 using Alberta CPI in 2007 GTA study
- Removed one project that was cancelled
- Added 17 new load-only interconnection projects
  - From 2006 to 2009
- Updated project costs to most recent estimates or final costs
  - Minimum +20%/-10% (“PPS”) estimate or better
- All project costs based on AESO Standard Facilities

**Composite Price Index**

- Project costs escalated to 2008 using composite price index
- Based on four historical price indices from Statistics Canada
  - Canada equipment index ▶ substations
  - Canada materials index ▶ transmission line
  - Alberta industrial services index ▶ engineering
  - Average of Calgary and Edmonton industrial structures indices ▶ construction
- Historical price indices weighted in proportion to average weighting of cost components for interconnection projects
- Project costs escalated from 2008 to 2010 using forecast of Alberta CPI
POD Cost Function Increase

- 2007 POD cost function:
  \[ \text{Cost} = 2,213,108.54 \times \text{MW}^{0.37} \]

- 2010 POD cost function:
  \[ \text{Cost} = 2,542,800 \times \text{MW}^{0.4197} \]

- Power curve remains “best fit” to data
- Shape of curve essentially unchanged
- Increases of:
  - 27% at 7.5 MW
  - 32% at 17 MW
  - 38% at 40 MW

2010 Cost Function Is About 35% Higher than 2007 Cost Function

![Graph showing POD Cost ($000 000) vs. DTS Capacity (MW)]
Shape of Curve Is Essentially Unchanged

Next Steps

- Final discussion paper planned for mid-July
  - Data will be distributed with discussion paper
- Stakeholder comment process on discussion paper
- Final results will be incorporated into 2010 tariff application
TFO O&M Cost Causation Study

John Martin
Director, Tariff Applications, AESO Regulatory

Study Status

- Study being completed for AESO by Arnie Reimer of PS Technologies
- Study scope developed and reviewed
- Initial interviews completed with TFOs
  - Study will be based on information from four largest TFOs: AltaLink, ATCO Electric, ENMAX, and EPCOR
- Study will examine costs from 2005 to 2009
- O&M costs will be defined broadly to include all non-capital costs
  - All costs except depreciation, return, income tax, and related costs
  - Includes operation and maintenance, general, and administrative costs
Preliminary Results

- Study is less data-intensive than wires cost causation study
- O&M costs appear to generally be considered demand-related costs
  - O&M primarily to maintain or improve reliability
  - Expected to increase demand weighting of bulk system and local system functions
- O&M costs appear to be:
  - Less than average for bulk system function
  - More than average for local system function
  - Average for point of delivery function
  - Expected to shift costs from coincident demand charge in bulk system to billing capacity demand charge in local system

Impact on Cost Functionalization and Classification

Impact on Results From Wires Cost Causation Study

<table>
<thead>
<tr>
<th>Function</th>
<th>Total</th>
<th>Demand ($/MW)</th>
<th>Usage ($/MWh)</th>
<th>Customer ($/month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>41.7%</td>
<td>34.2%</td>
<td>7.5%</td>
<td>–</td>
</tr>
<tr>
<td>Local System</td>
<td>17.4%</td>
<td>14.3%</td>
<td>3.1%</td>
<td>–</td>
</tr>
<tr>
<td>POD</td>
<td>40.9%</td>
<td>35.0%</td>
<td>–</td>
<td>5.9%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>83.5%</td>
<td>10.6%</td>
<td>5.9%</td>
</tr>
</tbody>
</table>

Note: Totals may not add due to rounding
Next Steps

- Finish study over summer
- Release study in early September
- Stakeholder comment process on study
- Final results will be incorporated in 2010 tariff application

Operating Reserve Charge Investigation

Raj Sharma
Senior Tariff Analyst, AESO Regulatory
Operating Reserve Charge

- DTS operating reserve charge recovers costs of active and standby operating reserves (regulating, spinning, and supplemental)
  - Also recovers related amounts, including trading fees, non-compliance charges, and liquidated damages
- Operating reserve costs are forecast to be $236 million in 2009
  - Related amounts totalled $7 million credit in 2008
- All costs are incurred hourly
  - Related amounts are billed in month following production

Operating Reserve Charge Review

- AESO had initially proposed moving from single-block to two-block operating reserve charge
  - Reduced deferral account balances significantly
- Stakeholders recommended AESO consider hourly allocation of operating reserve costs
- Hourly allocation appears feasible
  - Hourly operating reserve costs would be allocated over all DTS load in each hour
  - Allocation would be completed at month end and included on preliminary and final statements
Hourly Operating Reserve Charge

- AESO will maintain single-block operating reserve charge to allow customers to estimate magnitude of charge
  - Actual charge would be calculated from actual costs
- Operating reserve charge deferral account significantly reduced
  - Deferral account would likely still be used for related amounts
- AESO investigating how to provide information to allow customer to verify billing charges

Next Steps

- Finalize review of feasibility of hourly charge
- Final discussion paper planned for early August
- Stakeholder comment process on discussion paper
- Final results will be incorporated into 2010 tariff application
2010 Rate Proposals

John Martin
Director, Tariff Applications, AESO Regulatory

Rate Levels

- Rate levels will initially be based on 2009 costs as filed in AESO 2009 Rates Update application
  - Wires costs will be updated with recent TFO tariff approvals
- Rate levels will be updated to reflect 2010 costs when those costs are approved late in 2009
  - TFO costs will also be updated if further TFO tariff approvals occur
- Working groups examining:
  - Fort Nelson Rate
  - export and import rates
  - Primary Service Credit
  - deferral account Riders B and C
**Demand Transmission Service Rate DTS**

- Interconnection charge updated to reflect
  - (a) updated POD cost function, and
  - (b) updated wires cost functionalization and classification from TFO O&M costs causation study
    - No changes to structure, billing determinants, or methodology
- Operating reserve charge revised to:
  
  highest 15-minute Metered Demand in each hour \( \times \) operating reserve unit cost in each hour

  where operating reserve unit cost is the total cost of operating reserves in the hour divided by the sum for all DTS customers of the highest 15-minute Metered Demand for each customer in the hour

**Demand Transmission Service Rate DTS (cont’d)**

- No change to voltage control charge
- No change to $/MW component of other system support service charge
- Power factor deficiency charge will increase
  - Still determining appropriate level
  - Threshold will remain at 90% power factor during interval of highest Metered Demand
DTS Interconnection Charge

Preliminary Comparison

<table>
<thead>
<tr>
<th>Component</th>
<th>2009 Rates Update</th>
<th>2010 Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>$2,229.00/MW, $0.78/MWh</td>
<td>$2,156.00/MW, $0.51/MWh</td>
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<tr>
<td>Local System</td>
<td>$653.00/MW, $0.32/MWh</td>
<td>$866.00/MW, $0.22/MWh</td>
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<tr>
<td>Point of Delivery</td>
<td></td>
<td></td>
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<tr>
<td>First (7.5 × SF) MW</td>
<td>$3,955.00/MW</td>
<td>$3,920.00/MW</td>
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<tr>
<td>Next (9.5 × SF) MW</td>
<td>$1,368.00/MW</td>
<td>$1,495.00/MW</td>
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<td>Next (23 × SF) MW</td>
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<td>All Remaining MW</td>
<td>$425.00/MW</td>
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<td>Fixed Component</td>
<td>$7,030.00 × SF</td>
<td>$5,270.00 × SF</td>
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</tbody>
</table>

SF = Substation Fraction

Fort Nelson Demand Transmission Service Rate FTS

- Working group discussion has focussed on assessing costs in three time frames:
  - the current situation with significant TMR requirements,
  - after the northwest transmission development is complete, when the need for TMR is reduced, and
  - after significant load growth in the future when either TMR is again required or additional transmission development is needed

- Working group has not yet completed examination of issues
Fort Nelson Demand Transmission Service Rate FTS (cont’d)

- AESO is generally supportive of:
  - continuing current rate for loads included in the northwest transmission development need application, and
  - serving incremental load growth beyond those levels by prorating future incremental costs over total incremental load growth

- Working group will continue to examine issues in support of a proposal to be included in the AESO’s 2010 tariff application

Demand Opportunity Services Rates DOS

- No changes to structure, billing determinants, or methodology
  - Rate levels will change to reflect changes in costs

- Integrate some terms and conditions onto rate sheets
Export Transmission Service
Rates XTS

- Rate XTS would provide a “firm” export service comparable to Rate DTS load service
- Export and import rates working group suspended to allow a separate interties workgroup to develop a vision and product requirements for export and import services
- Export and import rates working group will resume meeting when interties work is complete
  - Interties work is expected to be completed in July
- Work may not be completed in time to be included in 2010 tariff application, and may require a supplemental or amendment application

Export Opportunity Services
Rates XOS

- No changes to structure, billing determinants, or methodology
  - Rate levels will change to reflect changes in costs
  - Rate levels will also reflect any changes arising from implementation of WECC BAL-002 contingency reserve standard
Demand Under-Frequency Load Shedding Credit Rate UFLS

- No changes to structure or billing determinants
- AESO is examining whether Rate UFLS should apply to direct-connect load customers
  - Currently Rate UFLS applies to distribution facility owners only

Primary Service Credit Rate PSC

- No changes to structure, billing determinants, or methodology
  - Rate levels will change to reflect changes in costs
- 55% of DTS POD charge components continues to represent share of costs attributable to substation
  - Based on updated data set used for POD cost function update
- Working group examining effectiveness of PSC price signal
  - Credit based on average embedded cost
  - Customer incurs specific incremental cost when building own substation
Supply Transmission Service
Rate STS

- No changes to structure, billing determinants, or methodology
- RGUCC levels will reduce in accordance with existing schedule of charges

Import Transmission Service
Rate ITS

- Rate ITS would provide a “firm” import service comparable to Rate STS generation service
- As with Rate XTS, export and import rates working group was suspended and will resume meeting when interties work is complete
- Work may not be completed in time to be included in 2010 tariff application, and may require a supplemental or amendment application
Import Opportunity Services Rates IOS

- No changes to structure, billing determinants, or methodology
  - Possibility of additional opportunity services to provide additional priority distinctions, based on product requirements developed by interties workgroup

Riders

- DAT Riders A1–A4: no changes
- Working Capital Deficiency/Surplus Rider B:
  - increase to threshold (currently $7.0 million)
  - clarification of process
- Deferral Account Adjustment Rider C:
  - change to include prior year balances
  - examining other possible changes in working group
  - also examining possible changes to reconciliation approach and process
- Losses Calibration Factor Rider E: no change
- Balancing Pool Consumer Allocation Rider F: no change
Deleted Riders

- Bill Impact Mitigation Rider G
  - Expires December 31, 2009
- Interim Refundable Fort Nelson Rider H
  - Addressed as part of Rate FTS

Amortized Contribution Option
Rider I

- Would allow credit-worthy customers to pay customer contributions over time rather than as up-front cash payment as currently required
- Would be available to both DTS and STS customers
- Credit-worthiness test may be restrictive
- Matters such as term, recalculation, and triggers for repayment still being examined in working group
Wind Forecasting Cost Recovery
Rider J

- As part of implementation of market and operational framework, AESO is proposing a centralized wind forecasting service with costs recovered from wind generators
- Cost will likely be recovered under a rider approved as part of the AESO’s tariff
  - Rider would apply only to wind generators
  - Rider would likely be on a $/MWh production basis
- AESO will consult with wind stakeholders on design and implementation of rider

Rate Appendix
Regulated Generating Units

- No material changes contemplated
- Incorporate relevant provisions from Article 14.6
2010 Terms and Conditions Proposals

John Martin
Director, Tariff Applications, AESO Regulatory

Terms and Conditions Changes

• Update throughout to reflect changes in legislation, rules, and standards
• Interconnection process will be revised through separate initiative
  – Revised process will be reflected in terms and conditions
• Working groups examining:
  — TOAD-related changes
  — customer contribution policy
**Article 1**  
**Definitions**

- AESO proposes to combine definitions from all authoritative documents into a single centralized glossary  
  - Definitions would be used consistently in tariff, rules, and reliability standards
- Definitions would then no longer appear in tariff
- Definitions must be approved before residing in centralized glossary  
  - AESO will apply for approval of definitions and movement to centralized glossary as part of 2010 tariff application
- Definitions used in a single article would be embedded in that article rather than moved to glossary

**Article 2**  
**Application of Tariff**

- Clarify that current tariff applies to all customers, unless exceptions are identified  
  - Such as original investment policy applying for contract changes that do not require construction
- No other material changes
Article 3
Provision of Service

• Will state that service may be subject to remedial action schemes or special protection schemes
• No other material changes

Article 4
Interconnection Requirements

• Removal of information already addressed in technical requirements
  – Primarily Article 4.4 for generating units
  – Already required in interconnection technical requirements
**Article 5  
System Access Applications**

- Will be significantly revised to align with redesigned interconnection process
- Customer will work directly with TFO or own consultant
- Two processes are contemplated, one for load interconnections and one for generator interconnections
- Application fees will be eliminated
- Process will be developed over summer and included in 2010 tariff application when filed

**Article 6  
Security and Agreements**

- Will be significantly revised to align with redesigned interconnection process
- Security requirements will be revised to align with expenditure of costs by TFOs
Article 7
Metering

• Removal of information already addressed in technical requirements
  – Several paragraphs include requirements already included in Metering Standard

Article 8
Provision of Information

• Removal of information already addressed in technical requirements
  – Several paragraphs already required in data and reporting standards
Article 9
Contribution Policy

• Clarification of contribution payment requirements
  – Amortized contribution option to be available to credit-worthy customers through Rider I
  – Otherwise, contribution payments to be staged to follow costs as incurred

• Further guidance on determination of system- and customer-related costs

• Further guidance on determination of AESO standard facilities
  – Will likely reside in policy document outside of tariff

• O&M charge will be updated based on TFO O&M study
  – Application will also reflect decision in R&V proceeding

Article 9 (cont’d)
Investment Levels

• Investment levels will be increased to reflect updated POD cost function
  – Will continue to use multiplier of 1.15 on average POD cost function

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<tr>
<th>Component</th>
<th>2007 Tariff</th>
<th>2010 Application</th>
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<td>First (7.5 × SF) MW</td>
<td>$28,900/MW/year</td>
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<td>Next (9.5 × SF) MW</td>
<td>$10,000/MW/year</td>
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<td>Fixed Component</td>
<td>$51,400 × SF/year</td>
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</table>
Article 9 (cont’d)
Greenfield Investment Comparison

- Clarify that maximum investment will be based on contract capacity increase since last investment
  - Rather than increase at time of request (as is current practice)
- Clarifications of staged load, cost changes, contribution changes, and shared facility requirements
- No changes to generator system contribution requirements
Article 10
Demand Opportunity Service (DOS)

- Consolidate terms onto rate sheets if possible
- Move business practices to ISO Rules or into information document

Article 11
Ancillary Services (TMR)

- No changes contemplated
Article 12
Under-Frequency Load Shedding

• Consolidate terms onto rate sheet if possible

Article 13
Capacity Increases and Allocation

• Will be significantly revised to align with redesigned interconnection process
• Details will be developed over summer and included in 2010 tariff application when filed
Article 14
Reductions or Terminations

- Clarify that payment in lieu of notice is based on present value of local system charge only
- Explicitly require payout of RGUCC charges in the event of termination of RGU service before end of base life
- Move regulated generating unit provisions in Article 14.6 to Rate Appendix

Article 15
Security and Billing

- Explicitly state that interest will not apply to adjustments to statements of account
- Review provisions and applicability for late payment charges
Article 16
Peak Demand Waiver

• No material changes contemplated

Article 17
Interruptions and Force Majeure

• No material changes contemplated
Article 18
Limitation of Liability

• No material changes contemplated

Article 19
Dispute Resolution

• Investigating consolidation of dispute resolution procedures in ISO Rules
  - Provides consistency of process

• Tariff would incorporate process by reference to ISO Rule
Article 20
Confidentiality

• ISO Rule being developed to comprehensively address confidentiality matters
• Propose to remove confidentiality requirement from tariff to avoid redundancy

Article 21
Miscellaneous

• No material changes contemplated
Appendix A
Metering Equipment

- Propose deleting appendix as information already addressed in Metering Standard

Appendix B
Agreement Proformas

- Being reviewed to better address needs of AESO and customers
- Will align with redesigned interconnection process
Appendix C
Procedure for TMR Procurement

• No material changes contemplated

Next Steps
John Martin
Director, Tariff Applications, AESO Regulatory
Next Steps

• Completion of working group discussion in July 2009
  – Possibility for some groups to continue into August
• Distribution of slide presentation with notes for stakeholder comment in July 2009
• Development of tariff detail during August
• General stakeholder meeting in early September
• Discussion paper and final opportunity for feedback in mid-September
• Tariff application filed in late September
• Effective date of 2010 tariff likely to be early 2011

Discussion and Questions
For More Information

- John Martin
  Director, Tariff Applications
  403-539-2465 or john.martin@aeso.ca

- Lee Ann Kerr
  Manager, Tariff Applications
  403-539-2741 or leeann.kerr@aeso.ca

- Raj Sharma
  Senior Tariff Analyst
  403-539-2632 or raj.sharma@aeso.ca

- Consultation documents on AESO web site at www.aeso.ca
  Tariff ▶ Current Consultations ▶ 2010 Tariff
June 11, 2009

AESO 2010 Tariff Consultation Working Group Members
AESO Stakeholders

Dear Stakeholder:

Re: General Stakeholder Meeting on AESO 2010 Tariff Application

Since the stakeholder meeting held on April 15, 2009, the AESO has been working with the small groups established as part of its 2010 tariff consultation as well as further examining matters expected to be addressed in the 2010 tariff application.

To update stakeholders on the progress of working group discussions and application planning, the AESO is holding a general stakeholder meeting as follows:

- **Time:** 1:30 to 4:30 PM
- **Date:** Wednesday, June 24, 2009
- **Location:** Bow Valley Room, Westin Hotel, 320 – 4th Avenue SW, Calgary
- **Refreshments:** Coffee, juice, soft drinks, and snacks
- **RSVP:** By Monday, June 22, 2009 to Ghaz Marinho, 403-539-2474 or ghaz.marinho@aeso.ca.

At the meeting the AESO expects to discuss:
- a summary of discussions held with working groups,
- an overview of proposed tariff changes expected to be included in its 2010 General Tariff Application
- the remaining steps in the consultation process, and
- the current plan for filing the application in the third quarter of 2009 and later updating it to include 2010 forecast costs and billing determinants.

Stakeholders who are unable to attend this consultation meeting but would like to discuss these matters with the AESO are invited to contact me to arrange a convenient time for such discussion.

Information related to the tariff consultation process, including working group discussions, is available on the AESO’s web site at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
Raj Sharma, Senior Tariff Analyst, AESO
Ghaz Marinho, Administrative Assistant, AESO
AESO 2010 Tariff Stakeholder Consultation

John Martin, David Michaud, and Raj Sharma
AESO Regulatory
April 15, 2009 — Calgary

Agenda

• Introduction (slides 1-6)

• Studies
  – POD cost function update (slides 7-17)
  – Maximum investment level update (slides 18-20)
  – TFO O&M cost causation study scope (slides 21-23)

• Rates
  – Restructuring of DTS operating reserve charge (slides 24-48)
  – Changes to DTS power factor deficiency charge (slides 49-52)
  – Changes to Fort Nelson Rate FTS (slides 53-54)
  – Possible higher priority (“firm”) export Rate XTS (slide 55)
  – Possible higher priority (“firm”) import Rate ITS (slides 56-57)
  – Changes to deferral account Riders B and C (slides 58-59)
Agenda (cont’d)

- Break
- Terms and conditions
  - Tariff changes in conjunction with TOAD project (slides 60-63)
  - Changes to interconnection process articles (slide 64)
  - Changes to AESO standard facilities definition (slides 65-67)
  - Amortized payment option for contributions (slides 68-69)
  - Further discussion on staged contributions (slide 70)
- Formation of working groups (slides 71-73)
- Next steps (slides 74-76)

Recent Applications

- AESO 2009 Rates Update
  - Filed March 12, 2009
  - 19% increase to DTS rate to reduce reliance on deferral account Rider C
  - Requested approval to be effective July 1, 2009
- AESO 2008 Deferral Account Reconciliation
  - Filed April 9, 2009
  - Reconciliation of $6.4 million net shortfall in deferral accounts
  - Requested interim approval to settle with customers in June 2009
AESO 2010 Tariff Application

- Plan to file in third quarter of 2009
- Stakeholder consultation February-June 2009
  - Individual stakeholder meetings held in February-March 2009
- Evolution of existing tariff
  - No major content changes (although potential movement between tariff and other authoritative documents)
  - Many minor changes
- Discussion papers and comment processes to review proposals
- Small working groups to develop specific issues

Meeting Objectives

- Understanding of preliminary results of studies being prepared for tariff application
- Discussion and development of scope and possible approaches for tariff proposals
- Set up working groups to address specific issues
- Establish expectations for remainder of consultation process and for filing of application
- Proposals are discussed “without prejudice” and may not be included or may be different in tariff application when filed
- Please ask questions during presentations
POD Cost Function and Investment Level Update

Raj Sharma
Senior Tariff Analyst, AESO Regulatory

Agenda

- Purpose
- Scope
- Method
- Inflation
- Raw cost function
- Upgrades
- Multiplier
- Proposed cost function
- Investment level implications
Purpose

- Update POD data set to include recent projects
  - 17 new projects since the last study
  - One project from last data set cancelled
  - Cost estimates may have changed or final costs may be available
- Examine which project cost inflator is appropriate
  - Alberta Consumer Price Index (CPI)
  - Composite index as proposed by Stakeholder Working Group
  - Composite index constructed by the AESO
- Compare the cost of upgrade projects to cost function
- Propose a new DTS POD cost function

Scope

- Update project information
- Include new projects
- Derive a project cost inflator index
- Determine raw greenfield interconnection project cost function
- Calculate cost per increased capacity for upgrade projects
- Calculate cost per capacity for greenfield projects
- Choose a multiplier
No Changes to Method Used in 2007 Refiling

- Included DTS-only projects that have no customer ownership
- Used latest project cost information (excluding 12% O&M)
  - Cost estimates ±20% or better or final costs
  - Based on cost of AESO Standard Facilities for project
- Project cost inflated to 2010 using Alberta CPI
- Determined relation between project cost and capacity
- Linearized the relation
- Divided the cost using Substation Fraction (SF)
- Used the existing multiplier of 1.15

Alberta CPI Is Close to Composite Price Index Over 1987-2007

[Graph showing Alberta CPI and Composite Index]
Power Function Provides Highest Correlation for Raw Greenfield Cost

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function (SM)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (Power)</td>
<td>$y = 2.2131 + x^{0.8117}$</td>
<td>0.4941</td>
</tr>
</tbody>
</table>

Based on 48 projects from 1987-2007

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function (SM)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed (Power)</td>
<td>$y = 2.4423 + x^{0.8096}$</td>
<td>0.4321</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>$y = 2.5394 + \text{Ln}(x) + 1.7269$</td>
<td>0.3795</td>
</tr>
<tr>
<td>Linear</td>
<td>$y = 0.0972 + x + 6.3146$</td>
<td>0.1834</td>
</tr>
<tr>
<td>Exponential</td>
<td>$y = 5.3514 + e^{0.0131 \times x}$</td>
<td>0.2012</td>
</tr>
<tr>
<td>Cubic</td>
<td>$y = 0.8505 - x^3 - 0.011 \times x^2 + 0.6125 \times x + 1.8761$</td>
<td>0.3432</td>
</tr>
<tr>
<td>Quadratic</td>
<td>$y = -0.0016 + x^2 + 0.2638 + x + 4.435$</td>
<td>0.2528</td>
</tr>
</tbody>
</table>

Based on 64 projects from 1987-2009

Update Cost Function Similar to Current Cost Function
Linear Cost Function With Same Breakpoints (7.5, 17 and 40 MW)

Upgrade Projects Adequately Covered by Cost Function
Preliminary DTS POD Cost Function

- DTS POD Cost
  
  \[ \text{DTS POD Cost} = \$0.959 \text{ million} + \$0.768 \text{ million/MW} \times \text{first (7.5 \times SF) MW} \]
  \[\quad + \$0.301 \text{ million/MW} \times \text{next (9.5 \times SF) MW} \]
  \[\quad + \$0.187 \text{ million/MW} \times \text{next (23 \times SF) MW} \]
  \[\quad + \$0.105 \text{ million/MW} \times \text{remaining MW} \]

Linear Cost Function With Multiplier of 1.15

Graph showing linear cost function with and without multiplier of 1.15.
## Multiplier of 1.15 Gives Results Similar to AUC 2007 Results

<table>
<thead>
<tr>
<th>Project Costs Covered by Investment</th>
<th>AUC 2007 Study with a multiplier of 1.15</th>
<th>AESO 2009 Study with a multiplier of 1.00</th>
<th>AESO 2009 Study with a multiplier of 1.15</th>
</tr>
</thead>
<tbody>
<tr>
<td>% receiving 100% investment</td>
<td>56%</td>
<td>48%</td>
<td>62%</td>
</tr>
<tr>
<td>% receiving 90-100% investment</td>
<td>12%</td>
<td>11%</td>
<td>11%</td>
</tr>
<tr>
<td>% receiving 80-90% investment</td>
<td>10%</td>
<td>12%</td>
<td>6%</td>
</tr>
<tr>
<td>% receiving 80-100% investment</td>
<td>79%</td>
<td>72%</td>
<td>80%</td>
</tr>
</tbody>
</table>

## Next Steps

- Discussion paper and stakeholder comments
- Refinements to study
- Finalization of study
- Apply for new cost function as part of 2010 tariff application
- Continue to collect data and analyze for future tariff applications
- Revisit the issue in next GTA
TFO O&M Cost Causation Study

David Michaud
Manager, AESO Regulatory

Purpose

- Respond to AUC directions in decisions on AESO tariff applications
  - Determine percentage of TFO costs related to O&M that are energy related
  - Conduct further analysis of incremental TFO O&M costs
- Determine if a material percentage of TFO O&M costs are energy related
- Determine if transmission functionalization is the same for both capital and O&M costs
TFO O&M Cost Causation Study Scope

- Summarize TFO revenue requirement separating capital and O&M costs
  - Using most recent three years of TFO tariff filings
- Study O&M costs over facility life
- Determine relationship of O&M costs to:
  - Capital costs
  - Bulk system, local system, and POD transmission functions
  - Demand related, energy related, and fixed components

Operating Reserve Charge Investigation

Raj Sharma
Senior Tariff Analyst, AESO Regulatory
Agenda

- Purpose
- Observation
- Possible rates
- Criteria
- Method
- Results
- Sensitivity and further analysis
- Further Results
- Selection
- Performance

Current Charge Results in Large Deferral Account Balances
Changes in Operating Reserve Costs Are Related to Pool Price

Possible Rates That Are a Stronger Function of Pool Price

- Hourly On/Off-Peak: x1 for 7am-11pm and x2 for 11pm-7am
- Block: x1 when PP is <=P1 and x2 when PP is > P1
- Exponential: x1 * exp (PP*x2)
- Linear: x1 * PP + x2
- Quadratic: x1 * PP^2 + x2 * PP + x3
- Power: x1 * PP^x2
- Block Continuous: x1 * PP when PP <=P1 plus an additional x2 * (PP-P1) when PP > P1
- Block Continuous with a Floor: F + x1 * PP when PP <=P1 plus an additional x2 * (PP-P1) when PP > P1
Criteria

- Recover forecasted annual OR cost
- Minimize monthly variance between cost and revenue
- Sensitivity to Pool Price
- Sensitivity to DTS MWh volume
- Simplicity
- Clarity
- Easy to administer

Method

- For each year, forecast a rate that recovers forecasted annual cost using forecasted hourly PP and forecasted hourly DTS MWh
- Calculate actual revenues using this forecasted rate, actual hourly PP, and actual hourly DTS MWh
- Compare performance of this rate to other rates
- Compare sensitivity of this rate to other rates
- Further analyze rate that performs best
### Monthly RMS Variance

<table>
<thead>
<tr>
<th>Rate</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hourly On/Off-Peak</td>
<td>6.37</td>
<td>6.63</td>
<td>7.08</td>
</tr>
<tr>
<td>Block</td>
<td>5.35</td>
<td>6.38</td>
<td>7.18</td>
</tr>
<tr>
<td>Exponential</td>
<td>14.69</td>
<td>12.52</td>
<td>9.67</td>
</tr>
<tr>
<td>Linear</td>
<td>6.29</td>
<td>7.13</td>
<td>7.49</td>
</tr>
<tr>
<td>Quadratic</td>
<td>64.71</td>
<td>25.29</td>
<td>6.65</td>
</tr>
<tr>
<td>Power</td>
<td>14.72</td>
<td>12.56</td>
<td>9.68</td>
</tr>
<tr>
<td>Block Continuous</td>
<td>4.64</td>
<td>5.78</td>
<td>6.76</td>
</tr>
<tr>
<td>Block Continuous With Floor</td>
<td>25.05</td>
<td>5.78</td>
<td>6.76</td>
</tr>
<tr>
<td>Actual</td>
<td>5.83</td>
<td>7.74</td>
<td>10.00</td>
</tr>
</tbody>
</table>

*P1 was rounded average of forecasted hourly PP*

### Sensitivity — 2006

Graphs showing sensitivity for different rate structures in 2006.
Best Rate

- Block Continuous rate appears to perform best
- In order to make the rate more deterministic, block size (i.e. P1) and ratio of the rates in two blocks (i.e. x1 and x2) can be fixed
- Varied P1 from $120-$180/MWh and ratio of the rates from 2-4 (i.e. x2 is 2-4 times x1)

Best Block Continuous Rate for Each Year

- 2006
  - Performs best when x2 is 2 times x1
  - Monthly RMS error is $3.2 million; annual error is $20 million
  - For P1=$150/MWh, x1=3.62% and x2=7.25%
- 2007
  - Performs best when x2 is 3 times x1
  - Monthly RMS error is $2 million; annual error less than $2 million
  - For P1=$150/MWh, x1=3.44% and x2=10.32%
- 2008
  - Performs best when x2 is 4 times x1
  - Monthly RMS error is $5 million; annual error less than $1.5 million
  - For P1=$150/MWh, x1=2.89% and x2=11.57%
Best Block Continuous Rate

• Three block rate reduced monthly RMS variance range by about $1-2 million
  – AESO proposes to make gradual changes to the OR rate and believes that additional complexity is not warranted at this time

• P1 can vary between $120-$180/MWh without degrading the results too much

• Ratio of the rates has significant effect on resulting variance

Best Block Continuous Rate (cont’d)

• Years that are expected to be similar to the immediate future should be given more consideration
  – 2008 had higher number of power plant outages and large variation in natural gas price
  – Because of economic downturn, Pool Price and thus Operating Reserve cost in 2009 is expected to be lower than in 2008
  – Approval of WECC BAL-002 standard will reduce Operating Reserve requirement thus possibly reducing OR cost
  – 2006 forecast was very different from the actual. Forecasting has improved since then and the difference has been quite small in 2007 and 2008
Rate Selection — Ratio of 2

[Graphs showing data points and trends]

Rate Selection — Ratio of 2.5

[Graphs showing data points and trends]
Rate Selection — Ratio of 3

Best Rate — Ratio of 2.5 Best Overall

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Variance</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>Average Variance 2006-08</th>
<th>Absolute Average Variance 2006-08</th>
<th>Range 2006-08</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Maximum</td>
<td>7.68</td>
<td>2.25</td>
<td>6.32</td>
<td>5.42</td>
<td>5.42</td>
<td>10.71</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>-3.81</td>
<td>-10.88</td>
<td>-12.39</td>
<td>-9.03</td>
<td>9.03</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>1.74</td>
<td>-1.01</td>
<td>-1.73</td>
<td>-0.33</td>
<td>1.49</td>
<td></td>
</tr>
<tr>
<td>2.5</td>
<td>Maximum</td>
<td>8.32</td>
<td>2.10</td>
<td>6.64</td>
<td>5.71</td>
<td>5.71</td>
<td>17.53</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>-0.36</td>
<td>-5.53</td>
<td>-10.89</td>
<td>-5.59</td>
<td>5.59</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>3.44</td>
<td>-0.45</td>
<td>-1.19</td>
<td>0.60</td>
<td>1.69</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Maximum</td>
<td>13.29</td>
<td>3.06</td>
<td>6.91</td>
<td>7.75</td>
<td>7.75</td>
<td>16.54</td>
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<tr>
<td></td>
<td>Minimum</td>
<td>0.22</td>
<td>-4.19</td>
<td>-9.63</td>
<td>-4.53</td>
<td>4.68</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td>5.11</td>
<td>0.06</td>
<td>-0.73</td>
<td>1.48</td>
<td>1.97</td>
<td></td>
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</tbody>
</table>
2006-2008 Variance for a Ratio of 2.5

2009 Rate for Ratio of 2.5
The Operating Reserve Charge equals:

(a) For each hour in which Pool Price is less than or equal to $150.00/MWh:
   - Metered Energy \times 4.47\% \times \text{Pool Price}

plus

(b) For each hour in which Pool Price is greater than $150.00/MWh:
   - Metered Energy \times (11.18\% \times \text{Pool Price}) - $10.07/MWh
Performance of the Proposed Rate

Next Steps

- Discussion paper and stakeholder comments
- Revise
- Finalize
- Apply for the new rate
- Monitor performance of the new rate
- Continue to examine if three block rate results in significant improvement
- Revisit the issue in next GTA
Potential Changes to DTS Power Factor Deficiency Charge

- Current DTS rate includes power factor deficiency charge of “$400.00/MVA of Apparent Power Difference when Power Factor is less than 90% during the interval of highest Metered Demand in the Billing Period”
  - “Apparent Power Difference” is calculated during the interval of highest Metered Demand in the Billing Period as the difference between the metered Apparent Power and 111% of the Metered Demand
  - Charges do not apply at dual-use sites where generator responds to System Controller directions
- Poor power factor is resulting in constraints in some areas and causing unnecessary system losses
- Poor power factor identified as factor in power outages
Power Factor Deficiency Charge Comparison

- Power factor requirement: 90%? 95%?
- Measure at time of system peak, non-coincident customer peak, or continuously
- Discontinue waivers at sites with generation subject to system controller direction
- Penalty could increase as power factor worsens
- Power factor charge reflective of customer cost of correction or system cost of correction
Potential Changes to Fort Nelson Rate FTS

- AESO planned northwest transmission development to remove need for transmission must run (“TMR”) service in Rainbow Lake area
- Potential load growth in Fort Nelson area in BC could require continued use of TMR
  - Load growth in Rainbow Lake area greater in BC than in Alberta
- Incremental post-northwest development costs could be prorated between BC and Alberta based on incremental post-northwest development load growth
  - BC would receive incremental cost signal to drive appropriate transmission development choices

Fort Nelson Rate FTS Considerations

- Using incremental cost and load post-northwest development would recognize history of transmission supply to Fort Nelson from Alberta
- Costs charged to BC Hydro at Fort Nelson could be greater of postage stamp DTS rate component or incremental cost component
  - Similar to basis for current rate
- Costs could be recovered as monthly tariff charge
  - Would require appropriate termination provisions
Possibilities for Higher Priority Export Rate XTS

- Rate XTS proposed by AESO in 2007 GTA but rejected by interveners and AUC
  - Limited available transfer capacity ("ATC") in some hours
  - Cost too high
- Have conditions changed materially since 2007?
  - ATC still limited
- Is a new export service needed before Edmonton-Calgary reinforcement is complete?

Possibilities for Higher Priority Import Rate ITS

- Higher priority import rates examined previously but were considered to be too similar to existing opportunity rate
  - Recent interest in an import rate with priority similar to STS
- What minimum and maximum terms should apply to a higher priority ("firm") import rate?
- Should it include "take or pay" provisions?
- Should it include provisions for direct charging for ancillary services if required to support the import?
- Should it require a refundable payment like the generator system contribution?
  - What minimum capacity factor or other criteria should apply?
Issues With Additional Export and Import Services

- How to address AUC concern with allocating deep system costs to exports and imports over merchant lines?
- Additional priority rates require OASIS or similar system
  - Higher priority export opportunity rate already approved in AESO tariff but will not be available until OASIS is implemented

Potential Changes to Deferral Account Rider C

- Rider C purpose is “to restore the deferral account balances to zero over the following calendar quarter”
  - Requires forecasting of the upcoming quarter
  - For example, must forecast Q1 variance to determine Q1 Rider C
- Alternatively, could use only actual variances
  - May decrease Rider C variability
  - May cause AESO to hold surpluses and finance shortfalls longer
- Alternatively, could address variances over remaining months in calendar year, as opposed to next quarter
  - Similar to Rider E approach
- Could vary approach by rate component
Potential Changes to Deferral Account Rider B

- Rider B purpose is to recover unexpected deficiencies or refund unexpected surpluses of working capital
- Currently available only as a “percentage increase or decrease...applied to charges under the rate schedules...in the current Billing Period”
- Revise to allow for more specific implementation
  - By rate component
  - By MWh (like Rider C)
- Potentially possible to modify Rider C to accommodate Rider B purpose

Terms and Conditions Changes

John Martin
Director, Tariff Applications, AESO Regulatory
Tariff Changes in Conjunction With TOAD Project

- Transition of Authoritative Documents (“TOAD”) project will develop structure and framework for AESO authoritative documents
  - Three years to move documents to new framework
- AESO tariff is an authoritative document
- What tariff changes should be accommodated as part of TOAD project?
  - Tariff approval has longer timeline that other document approvals

Potential Changes in Conjunction With TOAD Project

- Move technical requirements currently in tariff to AESO technical standards
  - PSS and AVR requirements in Article 4
  - Metering requirements in Article 7
  - Metering equipment information in Appendix A
- Standardize and consolidate common requirements
  - Master set of definitions for all authoritative documents (Article 1)
  - Single dispute resolution process (Article 19)
  - Single set of confidentiality provisions (Article 20)
Potential Changes in Conjunction With TOAD Project (cont’d)

- Consolidate information that is currently dispersed
  - Interconnection process (Ts&Cs and business practices)
  - DOS requirements (rates, Ts&Cs, OPPs, business practices)
  - Where should such consolidated information reside?
- Must be able to articulate rationale for where information ultimately end up
- Should terms and conditions migrate to authoritative document format?

Potential Changes to Interconnection Process Articles

- Articles 4, 5, 6, and 13 deal with the process of providing system access service to a customer
- Business practice documents support this process
- Interconnection process continues to evolve at AESO
- How much detail is appropriate to tariff?
- What details can be left to business practice documents?
- How do we allow flexibility for future improvements to process?
Contribution Policy Changes

David Michaud
Manager, AESO Regulatory

Potential Changes to AESO Standard Facilities Definition

- Current definition:

“AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consists of a single radial transmission circuit and a single transformer to supply an individual Point of Connection
AltaLink Consultation Recommendations

- Guiding Principal 2.0, Recommendation 1:
  “AESO Standard Facilities” mean the most economical interconnection facilities which meet good utility practice including applicable reliability, protection, and operating criteria and standards
- Appendix A.1 – Standards of Service:
  Standards to serve as a guide for number of transformers (two transformers to supply a POD with peak loads above 15 MVA) and number of lines, with rural, urban, and industrial distinctions

Amortization Payment Options for Customer Contributions

- Management fee on customer contributions as part of the TFO revenue requirement
  - Proposed in ATCO Electric and AltaLink tariff applications
  - Could apply to all rate payers or just to customers paying contributions
- Optional rider added to AESO tariff (Amortized Customer Contribution Rider)
Issues With Amortization Payment Options

• Optional or mandatory?
• Conversion options?
  – One-time option
  – Available to new customers only or to all customers?
• Amortization term?
• Fairness to new and existing customers
• Available to DTS and STS customers?
  – Available for generator system contributions as well?
• Risk of default
• Rate based on TFO return on equity

Staged Contributions

• Contributions are currently paid before construction
• Could contributions be paid in installments with the final payment occurring prior to energization?
  – Aligned with costs incurred by TFO
• Potential issues:
  – Timing of payments
  – Risk of default
  – Fairness to new and existing customers
  – Who will administer?
  – Is rate of return applicable?
Next Steps

John Martin
Director, Tariff Applications, AESO Regulatory

Formation of Working Groups

- Possible working groups to explore:
  - Fort Nelson Transmission Service Rate FTS
  - export and import rates ETS and ITS
  - deferral account Riders B and C
  - tariff changes in conjunction with TOAD project
  - amortized payment option and other customer contribution matters
- Working groups would identify issues and explore alternatives
- Working groups would not be decision making body
  - Final decisions would be made by AESO
Formation of Working Groups (cont’d)

- Working group target size around 4-6 participants
- Working groups would meet every two weeks
- How to select working group participants?
- How to select working group topics and scope?

Next Steps

- AESO to prepare and distribute discussion material by end of April
  - Including forms for stakeholder comment
- Next large stakeholder meeting near end of May
Discussion and Questions

For More Information

- John Martin
  Director, Tariff Applications
  403-539-2465 or john.martin@aeso.ca

- David Michaud
  Manager, Regulatory Services
  403-539-2471 or david.michaud@aeso.ca

- Raj Sharma
  Senior Tariff Analyst
  403-539-2632 or raj.sharma@aeso.ca

- Consultation documents on AESO web site at www.aeso.ca
  Tariff ➤ Current Consultations ➤ 2010 Tariff
April 1, 2009

AESO Stakeholders

Dear Stakeholder:

Re: Update on Consultation for AESO 2010 Tariff Application

During February and early March 2009, the AESO met with several parties to discuss the AESO’s 2010 general tariff application (“GTA”) which we expect to file in the third quarter of 2009. An update on the consultation process is provided below, with an invitation for you to attend a meeting on the afternoon of Wednesday, April 15, 2009 in Calgary for further discussion of the 2010 tariff.

In the consultation letter posted on the AESO’s website on February 5, 2009, the AESO outlined its initial consultation process and attached a preliminary list of potential matters to be addressed in its 2010 GTA. The AESO has updated that list based on further review of the tariff by the AESO and on comments received from the following parties:

- Alberta Direct Connect Consumers Association (ADC),
- Cities of Lethbridge and Red Deer,
- Dual Use Customers (DUC),
- EnCana Corporation,
- Industrial Power Consumers Association of Alberta (IPCAA),
- Nexen,
- TransCanada Energy, and
- Utilities Consumer Advocate (UCA).

Substantive changes from the list posted on February 5 are indicated by a heavy black line in the right margin. The list is expected to continue to evolve as consultation progresses over the coming months.

As the next step in its consultation, the AESO is holding a general stakeholder meeting to discuss preliminary proposals for its 2010 GTA, as follows:

Date: Wednesday, April 15, 2009
Time: 1:30 – 4:30 PM
Place: Strand/Tivoli Room, Plus 15 Level, The Metropolitan Centre 333 – 4th Avenue SW, Calgary, Alberta
Refreshments: Coffee, juice, snacks
RSVP: By Monday, April 13, 2009 to April Walters, 403-539-2463 or april.walters@aeso.ca
The AESO currently expects to discuss the following topics during the meeting (numbered as in the attached list):

1 **Studies**
   1.1 Preliminary results of the POD cost function update study
   1.2 Scope and methodology for TFO O&M cost causation study

2 **Rates**
   2.1.3 Preliminary proposal for restructuring operating reserve charge in Rate DTS
   2.1.4 Potential changes to power factor deficiency charge in Rate DTS
   2.2 Potential changes to Fort Nelson Demand Transmission Service Rate FTS
   2.4.3 Possibilities for higher priority (“firm”) export Rate XTS
   2.8.1 Possibilities for higher priority (“firm”) import Rate ITS
   3.2 Potential changes to deferral account Riders B and C

3 **Terms and Conditions**
   4.0.2 Tariff changes in conjunction with the transition of authoritative documents (TOAD) project
   4.1.1 Potential changes to AESO standard facilities definition
   4.5 Potential changes to interconnection process articles
   4.9.2 Preliminary updates to maximum investment levels in AESO contribution policy
   4.9.11 Possibilities for amortized payment option for customer contributions
   4.9.13 Further discussion of staged contributions

The AESO will also discuss the next steps in the consultation process as well as the current plan for filing the application in the third quarter of 2009 and later updating it to include 2010 forecast costs and billing determinants. The AESO notes that this list of topics to be discussed during the meeting is subject to change as work progresses on different items.

The AESO plans to present information on these topics to facilitate discussion, and will post the presentation before the meeting if possible. Following the meeting, the AESO expects to distribute discussion documents and invite additional stakeholder comments.

In its February 5 consultation letter, the AESO contemplated the development of working groups to address specific topics in greater detail. Having reviewed stakeholder comments and the updated list of matters to be addressed in the 2010 GTA, the AESO proposes forming five working groups to review the following matters:
- Fort Nelson Transmission Service Rate FTS,
- export and import rates ETS and ITS,
- deferral account Riders B and C,
- tariff changes in conjunction with TOAD project, and
- amortized payment option and other customer contribution matters.

The AESO will review guidelines for these working groups and invite stakeholders to sign up for participation on them at the end of the consultation meeting.

Stakeholders who are unable to attend this consultation meeting but would like to discuss these matters with the AESO are invited to contact me to arrange a convenient time for such discussion.
As noted in the previous letter, the AESO hopes to complete consultation in June 2009, to allow the application to be filed in the following quarter.

Information related to the tariff consultation process will be available on the AESO’s web site at www.aeso.ca by following the path Tariff ➤ Current Consultation ➤ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

attachment

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
    Raj Sharma, Senior Tariff Analyst, AESO
0 GENERAL INFORMATION

0.1 Planned Consultation Activities
0.1.1 Feb 2009 – individual meetings with stakeholders who were active in the AESO’s 2007 GTA
0.1.2 Mar-Apr 2009 – public consultation cycle: discussion paper, meeting, and comments
0.1.3 May-Jun 2009 – public consultation cycle: discussion paper, meeting, and comments
0.1.4 Q3 2009 – filing of application

0.2 Rates Update
0.2.1 The AESO filed its 2009 rates update (Application No. 1604888 and Proceeding ID 177) on March 12, 2009
0.2.2 The AESO proposes to file such annual rates updates in years between tariff applications
0.2.3 Consider more frequent rates updates, perhaps triggered by significant increases arising from TFO tariff approvals
0.2.4 The AESO will include in its 2010 GTA a proposal to update tariff investment levels based on a public inflation index as part of the annual rates updates

0.3 AltaLink Contribution Policy Recommendations
0.3.1 The following recommendations are included in Terms and Conditions sections 4.1 and 4.9:
  • Recommendation 1 on contribution policy principles
  • Recommendation 5 on operations and maintenance charge
  • Recommendation 7 on contribution payment options
0.3.2 Recommendations 2 on standards of service and 3 on system rebuilds are being reviewed as AESO policy decisions rather than tariff matters
0.3.3 Recommendation 4 on automatic escalation of investment levels using an inflation index will be considered as part of annual rates updates
0.3.4 Recommendations 6 on transitions between tariffs and 8 for “load first” treatment of dual-use sites will not be proposed by the AESO

1 STUDIES

1.1 POD Cost Function Update
1.1.1 Add about 20 projects to database
1.1.2 Update inflation rate (using Alberta CPI) to trend costs to 2010
1.1.3 Re-calculate best-fit function with same breakpoints
1.1.4 Preliminary results indicate about 25% increase in cost function

1.2 TFO O&M Cost Causation
1.2.1 Respond to outstanding directions from Decision 2007-106 to study incremental TFO O&M and propose additional cost causation refinements if warranted
1.2.2 Contracted to Arnie Reimer of PS Technologies
1.2.3 Develop study scope and methodology in consultation with stakeholders

1.3 Bill Impact Analysis
1.3.1 Comparison for each POD of monthly bills under proposed rate and current rate
1.3.2 Will not be able to accurately estimate operating reserve charge under proposed rate

2 RATES

2.0 General
2.0.1 Update all rate levels to reflect current costs
2.0.2 2009 forecast costs included in application when filed in mid-2009
2.0.3 Update to 2010 costs when approved by AESO Board in late 2009
2.0.4 Update TFO costs at same time to reflect most recent final or interim TFO tariffs approved by AUC

2.1 Demand Transmission Service (DTS)
2.1.1 Update interconnection POD charge to reflect updated POD cost function
2.1.2 Consider whether ratchet level should be increased, modified, or replaced to more strongly discourage system use above contract capacity
2.1.3 Restructure operating reserve charge to better track costs and minimize deferral account
2.1.4 Assess power factor deficiency charge level and applicability at PODs with distribution-connected generation

2.2 Fort Nelson Demand Transmission Service (FTS)
2.2.1 Revise rate consistent with findings of final Fort Nelson proposal
2.2.2 Revise rate to be consistent with any changes to Rate DTS
2.2.3 Incorporate or replace Interim Rider H

2.3 Demand Opportunity Services (DOS)
2.3.1 Review DOS rates, Ts&Cs Article 10, OPPs, and business practice for integration and consolidation

2.4 Export Services (XOS)
2.4.1 Update XOS rates to reflect current costs
2.4.2 Review allocation of operating reserves to export rates to reflect requirements of new WECC BAL-002 contingency reserve standard
2.4.3 Propose new “firm” XTS rate, if appropriate after consultation

2.5 Demand Under-Frequency Load Shedding Credits (UFLS)
2.5.1 Review UFLS applicability to industrial customers
2.5.2 Consider possible differentiation between customers for defined reasons (such as environmental impacts of load shedding)
2.5.3 Review UFLS rates, Ts&Cs Article 12, and OPPs for integration and consolidation

2.6 Primary Service Credit (PSC)
2.6.1 Update PSC rate to be consistent with any updates to Rate DTS POD Charge
2.6.2 Update PSC proportion of DTS POD Charge as part of POD cost function update study

2.7 Supply Transmission Service (STS)
2.7.1 No material changes contemplated

2.8 Import Service (IOS)
2.8.1 Propose new “firm” ITS rate, if appropriate after consultation

3 RIDERS AND APPENDIX

3.1 Duplication Avoidance Tariff (DAT) Riders A1-A4
3.1.1 No material changes contemplated

3.2 Deferral Account Riders B and C
3.2.1 Revise to better manage deferral accounts, if appropriate after consultation
3.2.2 Revise to more accurately reflect cost basis of underlying components, if appropriate after consultation

3.3 Calibration Factor Rider E
3.3.1 No material changes contemplated

3.4 Balancing Pool Rider F
3.4.1 No material changes contemplated

3.5 Bill Impact Rider G
3.5.1 Expires at end of 2009

3.6 Interim Fort Nelson Rider H
3.6.1 Incorporated into or replaced by Rate FTS

3.7 Appendix: Regulated Generating Units
3.7.1 Incorporate regulated generating unit provision from Article 14.6

4 TERMS AND CONDITIONS OF SERVICE

4.0 General
4.0.1 Update throughout to reflect changes to legislation, rules, and standards
4.0.2 Incorporate TOAD-related revisions
4.0.3 Update to reflect current interconnection process
4.1 Definitions and Interpretation
4.1.1 Review “AESO Standard Facilities” definition in context of AltaLink contribution policy recommendation
4.1.2 Consider updating contract capacity to relate to physical requirement of customer and physical use of transmission system
4.1.3 Revise “Customer” definition to avoid confusion with EUA definition
4.1.4 Update “Transmission Interconnection Requirements” to refer to current standards and documents
4.1.5 Eliminate unused definitions (including “ratchet level”)
4.1.6 Update definitions to refer to or align with ISO Rules
4.1.7 Consider consolidating all definitions into a single master glossary for all AESO authoritative documents

4.2 Application of Tariff
4.2.1 Clarify that current tariff applies to all customers, with specific exceptions identified (such as original investment policy applying for contract changes that do not require construction)
4.2.2 No other material changes contemplated

4.3 Provision of System Access Service
4.3.1 Consider stating that constraints or remedial action schemes may apply in certain circumstances
4.3.2 No other material changes contemplated
4.3.3 Consider moving some or all system access service provisions requirements to ISO Rules as part of TOAD project

4.4 Customer Interconnection Requirements
4.4.1 Move PSS and AVR requirements to standards under ISO Rules
4.4.2 Consider moving all interconnection requirements to ISO Rules as part of TOAD project

4.5 System Access Application
4.5.1 Update to reflect current interconnection process
4.5.2 Remove requirement of DFO to provide security (to make consistent with Article 6.2(c))
4.5.3 Review assessment fee amounts and utilization
4.5.4 Consider moving some or all system access application process requirements to ISO Rules as part of TOAD project

4.6 Security and Customer Agreements
4.6.1 Update to reflect current interconnection process
4.6.2 Consider moving some or all security and customer agreement requirements to ISO Rules as part of TOAD project
4.7 Metering
4.7.1 Consider moving some or all metering requirements to ISO Rules as part of TOAD project

4.8 Provision of Information by Customers
4.8.1 No material changes contemplated
4.8.2 Consider moving some or all information provision requirements to ISO Rules as part of TOAD project

4.9 Customer Contribution Policy
4.9.1 Discuss contribution policy principles including, as appropriate, those identified in AltaLink contribution policy recommendation
4.9.2 Update investment levels to reflect updated POD cost function
4.9.3 Further clarify contribution requirements when customer chooses interconnection facilities other than the most economic option
4.9.4 Explicitly state that the contribution policy which applies to a project is the one in effect on the date that permit and license is issued by the AUC for the transmission facilities (rather than AltaLink contribution policy recommendation)
4.9.5 Further clarify determination of system and customer-related costs, if possible
4.9.6 Clarify that advancement provisions apply to all system projects, not just radial line
4.9.7 Consider incorporating provisions describing how parties directing benefiting from an intertie pay a share of the costs of that intertie in accordance with Transmission Regulation subsection 27(4)
4.9.8 Revise operations and maintenance charge in Article 9.4 in accordance with outcome of AUC review and variance of Decision 2007-106
4.9.9 Clarify substation fraction will be applied consistently to dual-use sites (and will not allow a deemed fraction of 1.0 at dual-use sites as proposed in the AltaLink contribution policy recommendations)
4.9.10 Calculate maximum local investment using increase in contract capacity since last investment rather than increase at time of request (to remove incentive to “hoard” capacity until investment is needed)
4.9.11 Consider an amortized payment option for customer contribution as discussed in AltaLink contribution policy recommendations
4.9.12 Consider materiality threshold for contribution payments or refunds, perhaps similar to $50,000 adjustment threshold for shared facilities (Article 9.10(c))
4.9.13 Respond to outstanding direction from Decision 2007-106 to conduct further analysis on staged contributions

4.10 Demand Opportunity Service
4.10.1 Consolidate and move sections as appropriate to rate schedules and ISO Rules
4.10.2 Consider moving some or all DOS business practices to ISO Rules as part of TOAD project
4.11 Ancillary Services
4.11.1 No material changes contemplated
4.11.2 Consider clarifying some aspects in guideline or other supporting document

4.12 Under-Frequency Load Shedding
4.12.1 Consolidate and move sections as appropriate to rate schedules and ISO Rules

4.13 Contract Capacity Increases and Allocation
4.13.1 Update to reflect current interconnection process
4.13.2 Move sections as appropriate to ISO Rules

4.14 Reductions or Termination of Contract Capacity
4.14.1 Consider limiting the number of changes permitted within a notice period
4.14.2 Clarify that payment in lieu of notice is calculated based on present value of local system charge only
4.14.3 Explicitly require the payout of remaining RGUCC charges in the event of early termination, in accordance with AUC findings in Decision 2007-106
4.14.4 Consider options to adjust contract capacity to reflect historical metered demand levels (for both DTS and STS customers)
4.14.5 Move regulated generating unit provision in Article 14.6 to the Regulated Generating Units Rates Appendix

4.15 Credit, Billing, and Payment Terms
4.15.1 Explicitly state that interest will not apply to adjustments to statements of account
4.15.2 Review provisions and applicability for late payment charges
4.15.3 Consider moving some or all credit, billing, and payment provisions to ISO Rules as part of TOAD project

4.16 Peak Metered Demand Waiver
4.16.1 No material changes contemplated

4.17 Service Interruptions and Force Majeure
4.17.1 No material changes contemplated

4.18 Limitation of Liability
4.18.1 No material changes contemplated

4.19 Dispute Resolution
4.19.1 No material changes contemplated
4.19.2 Consider consolidating some or all dispute resolution provisions into a single process for all AESO authoritative documents
4.20 Confidentiality
4.20.1 Update confidentiality provisions to align with participant involvement program requirements
4.20.2 Consider consolidating some or all confidentiality provisions into a single requirement for all AESO authoritative documents

4.21 Miscellaneous
4.21.1 No material changes contemplated

5 APPENDICES

5.1 Appendix A: Metering Equipment Information
5.1.1 Move sections as appropriate to metering standards under ISO Rules

5.2 Appendix B: System Access Service Agreement Pro Formas
5.2.1 Update to reflect current interconnection process
5.2.2 Consider adding commissioning agreement pro forma

5.3 Appendix C: Procedure for Foreseeable TMR Service
5.3.1 No material changes contemplated
February 5, 2009

AESO Stakeholders

Dear Stakeholder:

Re: Consultation for AESO 2010 Tariff Application

The AESO is beginning the consultation process for its 2010 general tariff application (GTA), which we expect to file in the third quarter of 2009. You are invited to become involved in this process.

Attached to this letter is the AESO’s preliminary list of potential matters to be addressed in the 2010 GTA. Initially, the AESO will seek comments on this list from those parties who were most actively involved in its 2007 GTA proceeding, as well as the Utilities Consumer Advocate. The AESO will accordingly contact the following parties in the next few days, to begin discussion on the preliminary list:

- Alberta Direct Connect Consumers Association (ADC),
- Consumers Coalition of Alberta and Public Institutional Consumers of Alberta (CCA/PICA),
- Dual Use Customers (DUC),
- EnCana Corporation,
- Industrial Power Consumers Association of Alberta (IPCAA),
- TransCanada Energy, and
- Utilities Consumer Advocate (UCA).

Other stakeholders are invited to contact the AESO if they wish to provide comments at this early stage.

Based on the initial discussions and review, the AESO will further develop the list of matters to be addressed, and plans to develop a discussion paper and hold broader consultation sessions on those matters. As well, it may be effective to develop working groups to address specific items in greater detail.

The preliminary list is intended as a starting point for discussion, and will evolve as consultation progresses over the coming months. The AESO hopes to complete consultation in June 2009, to allow the application to be filed in the following quarter.
The AESO requests stakeholders review the preliminary matters list, to ensure items of interest to them are included. The list contains various matters of different levels of significance. The AESO notes that the majority of its focus to date has been in the following areas (numbered as they appear on the list):

- 0.3 AltaLink contribution policy recommendations
- 1.1 POD cost function update
- 1.2 TFO O&M cost causation
- 2.1 Restructuring of operating reserve charge
- 2.2 Revisions to Rate FTS (and incorporation or replacement of Interim Rider H (3.6))
- 2.4 New “firm” export rate
- 2.8 New “firm” import rate
- 4.1 Coordination, consolidation, and updating of definitions
- 4.5 Updating to reflect the AESO’s current interconnection process
- 4.9 Updating and clarification of customer contribution provisions

The AESO will provide information to stakeholders in early March on the next stage of consultation on the 2010 tariff, which is expected to include broader stakeholder involvement.

Information related to the tariff consultation process will be available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultation ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403.539.2465 or john.martin@aeso.ca, or Raj Sharma at 403.539.2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

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cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO
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0.1.4 Q3 2009 – filing of application

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The AESO will also be filing a 2009 rates update in Q1 of 2009, and is considering such annual updates in years between tariff applications

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0.3.1 The following recommendations are included in Terms and Conditions sections 4.1 and 4.9:
• Recommendation 1 on contribution policy principles
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• Recommendation 7 on contribution payment options
0.3.2 Recommendations 2 on standards of service and 3 on system rebuilds are being reviewed as AESO policy decisions rather than tariff matters
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2.2.2 Revise rate to be consistent with any changes to Rate DTS
2.2.3 Incorporate or replace Interim Rider H

2.3 DOS
2.3.1 Review DOS rates, Ts&Cs Article 10, OPPs, and business practice for integration and consolidation

2.4 Export
2.4.1 Update XOS rates to reflect current costs
2.4.2 Propose new “firm” XTS rate, if appropriate after consultation

2.5 UFLS
2.5.1 Review UFLS applicability to industrial customers
2.5.2 Review UFLS rates, Ts&Cs Article 12, and OPPs for integration and consolidation

2.6 PSC
2.6.1 Update PSC rate to be consistent with any updates to Rate DTS POD Charge

2.7 STS
2.7.1 No material changes contemplated

2.8 IOS
2.8.1 Propose new “firm” ITS rate, if appropriate after consultation
3 RIDERS AND APPENDIX

3.1 DAT Riders A1-A4
3.1.1 No material changes contemplated

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3.2.1 Revise to better manage deferral accounts, if appropriate after separate consultation on deferral accounts

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3.3.1 No material changes contemplated

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4.1.4 Eliminate unused definitions (including “ratchet level”)
4.1.5 Update definitions to refer to or align with ISO Rules

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4.13 Contract Capacity Increases and Allocation
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4.14.1 Consider limiting the number of changes permitted within a notice period
4.14.2 Explicitly require the payout of remaining RGUCC charges in the event of early termination, in accordance with AUC findings in Decision 2007-106
4.14.3 Move regulated generating unit provision in Article 14.6 to the Regulated Generating Units Rates Appendix

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4.15.1 Explicitly state that interest will not apply to adjustments to statements of account
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4.17.1 No material changes contemplated

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4.18.1 No material changes contemplated

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4.19.1 No material changes contemplated

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5.3.1 No material changes contemplated