Preamble: At page 5 of Section 2, the AESO states:

The 2007 losses volumes forecast utilized 2001 to 2006 actual settlement volumes resulting in an anticipated reduction in forecast losses volumes for 2007. Additionally, the load forecast used for the 2006 loss forecast included a portion of industrial load whose contribution to total system losses was overstated, and monitoring of actual losses confirms the total system losses are not increasing as quickly as previously forecast.

At page 20 of Section 2, the AESO states:

The Losses volume forecast is produced on a monthly and annual basis. The AESO recovers the cost of Losses through charges that are indexed to pool price, consistent with the manner in which the costs are incurred. The forecasts provided in this section were reviewed via the ABRP and approved by the AESO Board.

……


Reference: Section 2 – Revenue Requirement, Page 5 of 34 and 20 of 34

Request:

(a) Please provide the “2001 to 2006 actual settlement volumes” in the reference and express them in monthly amounts and annual totals. Include a column that compares monthly and annual increases from 2006 forecast to 2005 actuals and 2007 forecast to 2006 forecast.

(b) Please explain how and why “a portion of industrial load whose contribution to total system losses was overstated”.

(c) If not already included in part (a) to this question, please provide a table similar to Revised Table 2.4.2 Transmission Losses Monthly Comparison of Volumes in TCE.AESO-107 ATTACHMENT A of the AESO 2005/2006 General Tariff Application that includes 2003, 2004 and 2005 Actuals, 2006 Actuals year to date for months available, 2006 Forecast and 2007 Forecast.

(d) Has the AESO considered the merits of a simple month to month forecast of losses based on the average of the same months for the previous two or three years adjusted for the overall annual forecast increase? Please explain.
(e) Please provide an estimate of the AESO resources required to generate the loss forecast and discuss whether, in light of the use of deferral accounts, this level of sophistication is worth the cost, noting the previous estimate of approximately two months labor provided in the 2005/2006 GTA.

Response:

(a) The AESO understands the request is for actual losses settlement volumes and not settlement volumes.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>246,434</td>
<td>207,173</td>
<td>244,907</td>
<td>258,705</td>
<td>265,826</td>
<td>301,614</td>
<td>289,898</td>
<td>254,761</td>
<td>9%</td>
<td>-12%</td>
</tr>
<tr>
<td>Feb</td>
<td>218,752</td>
<td>215,717</td>
<td>237,533</td>
<td>255,427</td>
<td>220,527</td>
<td>239,959</td>
<td>263,064</td>
<td>240,719</td>
<td>19%</td>
<td>-8%</td>
</tr>
<tr>
<td>Mar</td>
<td>244,648</td>
<td>241,841</td>
<td>246,870</td>
<td>279,464</td>
<td>249,313</td>
<td>267,993</td>
<td>285,814</td>
<td>263,337</td>
<td>15%</td>
<td>-8%</td>
</tr>
<tr>
<td>Apr</td>
<td>255,135</td>
<td>237,399</td>
<td>247,346</td>
<td>244,246</td>
<td>224,024</td>
<td>214,010</td>
<td>276,669</td>
<td>242,363</td>
<td>23%</td>
<td>-12%</td>
</tr>
<tr>
<td>May</td>
<td>240,209</td>
<td>240,578</td>
<td>211,392</td>
<td>238,767</td>
<td>246,440</td>
<td>238,387</td>
<td>256,361</td>
<td>248,130</td>
<td>4%</td>
<td>-3%</td>
</tr>
<tr>
<td>Jun</td>
<td>232,078</td>
<td>223,956</td>
<td>160,239</td>
<td>217,985</td>
<td>203,656</td>
<td>231,538</td>
<td>241,888</td>
<td>219,777</td>
<td>19%</td>
<td>-9%</td>
</tr>
<tr>
<td>Jul</td>
<td>237,813</td>
<td>253,823</td>
<td>218,357</td>
<td>217,773</td>
<td>238,842</td>
<td>224,617</td>
<td>265,653</td>
<td>248,055</td>
<td>11%</td>
<td>-7%</td>
</tr>
<tr>
<td>Aug</td>
<td>207,153</td>
<td>235,824</td>
<td>185,436</td>
<td>212,489</td>
<td>234,679</td>
<td>242,812</td>
<td>263,163</td>
<td>225,423</td>
<td>12%</td>
<td>-14%</td>
</tr>
<tr>
<td>Sep</td>
<td>193,266</td>
<td>203,312</td>
<td>238,574</td>
<td>193,665</td>
<td>234,419</td>
<td>222,087</td>
<td>239,763</td>
<td>223,314</td>
<td>2%</td>
<td>-7%</td>
</tr>
<tr>
<td>Oct</td>
<td>187,332</td>
<td>233,074</td>
<td>236,889</td>
<td>214,383</td>
<td>228,841</td>
<td>224,832</td>
<td>245,557</td>
<td>234,110</td>
<td>7%</td>
<td>-5%</td>
</tr>
<tr>
<td>Nov</td>
<td>202,992</td>
<td>217,105</td>
<td>233,815</td>
<td>224,657</td>
<td>239,253</td>
<td>253,250</td>
<td>264,451</td>
<td>237,386</td>
<td>11%</td>
<td>-10%</td>
</tr>
<tr>
<td>Dec</td>
<td>212,042</td>
<td>232,688</td>
<td>261,926</td>
<td>233,900</td>
<td>262,656</td>
<td>287,719</td>
<td>259,211</td>
<td>10%</td>
<td>-10%</td>
<td></td>
</tr>
<tr>
<td>Annual</td>
<td>2677855</td>
<td>2742490</td>
<td>2723284</td>
<td>2790951</td>
<td>2848477</td>
<td>2661099.1</td>
<td>3180000</td>
<td>2896586</td>
<td>12%</td>
<td>-9%</td>
</tr>
</tbody>
</table>

Values expressed as MW.hrs, as of January 10 2007. Please note the 2006 highlighted values may yet change as final settlement occurs.

(b) The 2006 losses forecast included growth in Behind The Fence (BTF) load. It was recognized that it was not appropriate to include BTF loads even though it would have minimal impact on overall system losses. BTF load growth has been removed from the 2007 losses forecast.

(c) Please refer to (a).

(d) Yes. The AESO reviews actual historical losses and possible trends in losses to forecast losses. Many variables affect the loss forecast including; generation patterns, hydro levels, annual and seasonal weather variations from norms, and interchange on the tie lines which may greatly affect losses from month to month. The suggested methodology, while simple, would be result in a less accurate forecast.

(e) The resources required to provide loss forecasting are estimated to be about two person-months per year. The AESO considers this level of sophistication is warranted considering the annual cost of losses (about $200 M) and its use in the determination of generator loss factors. Stakeholders have indicated a preference for a more accurate loss forecast.
Preamble: The AESO states:

The net impacts on rates of the changes detailed in this Application are an overall decrease of 3.2% in the Demand Transmission Service (DTS) rate and an overall decrease of 8.1% in the Supply Transmission Service (STS) rate. However, not all components of the DTS and STS rates are affected equally, and changes by component are summarized in Table 4.0.1.

Table 4.0.1 Change by Rate Component, 2006 to Proposed Tariff

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>DTS</th>
<th>STS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection Charge</td>
<td>1.1%</td>
<td>-</td>
</tr>
<tr>
<td>Losses Charge</td>
<td>-</td>
<td>(5.9%)</td>
</tr>
<tr>
<td>Operating Reserve Charge</td>
<td>(14.0%)</td>
<td>-</td>
</tr>
<tr>
<td>Voltage Control Charge</td>
<td>(5.1%)</td>
<td>-</td>
</tr>
<tr>
<td>Other System Support Services Charge</td>
<td>1.3%</td>
<td>-</td>
</tr>
<tr>
<td>Regulated Generating Unit Connection Costs</td>
<td>-</td>
<td>(6.7%)</td>
</tr>
<tr>
<td>Total Tariff</td>
<td>(2.7%)</td>
<td>(6.0%)</td>
</tr>
</tbody>
</table>

Note: The current 2006 Rates became effective January 1, 2006

Reference: Section 4 – 2007 Rate Design, Page 2 of 53

Request:

(a) Please reconcile the 3.2% decrease in the text for DTS customers with the Total 2.7% decrease shown in Table 4.0.1 for DTS customers.

(b) Please reconcile the 8.1% decrease in the text for STS customers with the 6.0% decrease shown in Table 4.0.1 for STS customers.

(c) Please provide the underlying schedule that shows the calculations in Table 4.0.1.

Response:

(a-c) Please refer to the response to Information Request ADC.AESO-015.
Preamble:  The AESO states:

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


Request:

(a) Please provide an analysis of the Wires Only – Cost Causation Study January 25, 2005 (Exhibit 02-012-010 in 2006 GTA) and the 2006 Transmission Cost Causation Update September 15, 2006 (Appendix C) that identifies all of the instances where expert judgment was exercised in the study or where information was missing or incomplete that could contribute to inaccuracy in the assignment or allocation of costs to the various functions and classes. Include explanations and references in the analysis.

(b) Please explain the differences between the Cost Causation study/Cost Causation Update in (a) above and a fully allocated cost of service study. Please explain if the AESO considers its cost causation study to be based on normal cost of service study practices or whether this study is unique to the AESO?

(c) Please confirm that, in general, the less accurate a cost causation study, the less weight that should be placed on that study in designing rates. If not confirmed, please fully explain.

(d) If the response to (b) identifies differences between a cost causation study and a fully allocated cost of service study, please confirm that, in general, the less accurate a fully allocated cost of service study, the less weight that should be placed on that study in designing rates. If no, please fully explain.

(e) Please identify the different kinds of cost of service studies, such as embedded versus marginal cost studies, that can be conducted on regulated assets and their corresponding strengths and weaknesses. Also comment on the basis for the choice of cost study undertaken by the AESO and state clearly what type of cost of service study was conducted.

Response:

(a) Studies included in previous GTAs were subject to review during those proceedings. Please refer to the 2006 Transmission Cost Causation Update (provided as Appendix C to the AESO’s 2007 GTA filed on November 3, 2006) for a discussion of methodology and assumptions.
(b) The original *Transmission Cost Causation Study* (TCCS) was a cost of service study in essence. Given that there is only one rate class responsible for the costs of the transmission system, the TCCS did not include the final step of cost of service studies in identifying revenue to cost ratios by rate class. The *2006 Transmission Cost Causation Update* is a study that addresses issues raised during the AESO’s 2005-2006 GTA proceeding. The TCCS used methods consistent with cost of service studies.

(c-d) In general, confirmed. Where a study is demonstrated to be inaccurate, such inaccuracy should be considered when determining what weight to accord the study.

(e) Please refer to Bonbright and other authors and publications for a description of the types of cost of service studies possible, and their corresponding strengths and weaknesses.
Preamble: The AESO states:

The Update recommends that high-voltage facilities in networked substations should be functionalized as local system rather than functionalized as POD as in the original Study. The Update also notes that sufficient data to complete such functionalization is not available nor expected to be available in the near future, and that the original functionalization as POD is generally consistent with the definition of customer-related facilities in the terms and conditions. In any event, aligning functional definitions in a cost study with facility definitions in a contribution policy may involve trade-offs in accuracy for one or the other purpose.

The Transmission Cost Causation Update also reviewed the functionalization of contributions in aid of construction (CIAC) in the original Study. The Update has improved the consistency of functionalization of CIAC amounts from all TFOs, and the impact on cost functionalization has been included in Tables 4.3.3 and 4.3.4 provided later in this section.

Finally, the Transmission Cost Causation Update included a review of dual-use substation costs, but concluded the functionalization of such costs could not be determined from analysis of the TFO cost data. The Update recognized that in Decision 2005-096 the EUB approved dual-use substation cost sharing based on the substation fraction approach. Substation fractions have therefore been used to apportion the cost of dual-use substations between demand (functionalized as POD) and supply (functionalized as bulk system) in the Update.


Request:

(a) Please provide the details of the functionalization of contributions in aid of construction (CIAC) in the original Study, with all supporting documents.

(b) Please explain how the substation fractions were used “to apportion the cost of dual-use substations between demand (functionalized as POD) and supply (functionalized as bulk system)” in the Update. In the response, include an explanation of why the supply portion was functionalized as bulk system. Also include an explanation of whether substation fractions were applied to the costs of individual PODs and if so, provide the details by individual POD. Include all working papers and supporting documents.

(c) Please provide a list of all PODs that are wholly owned and those owned 95% or more by the STS customer. Consider “ownership” to include direct ownership or cases where the customer contribution from the STS customer equals the capital cost of the POD (for
the wholly owned case) or is at least 95% of the capital cost of the POD (for those owned 95% or more). Also include their capital cost (before and after customer contributions) and the capital cost of the remaining PODs (before and after customer contributions) not included in the previous two categories.

(d) Please provide restated Tables 4.3.3 and 4.3.4 that separate the impact on cost functionalization of CIAC amounts and the cost of dual-use substations into separate columns so that the effect of these changes from the original to updated functions and classification can be identified.

Response:

(a) Please refer to the response to Information Request CG.AESO-021. The AESO considers details of customer contributions paid by specific customers to be confidential information.

(b) The apportionment can be demonstrated with an example of a substation with a net book value of $10,000,000, a DTS substation fraction of 25%, and an STS substation fraction of 75%. The POD portion of the substation is found by multiplying $10,000,000 by 25% for a POD portion of $2,500,000. The STS portion of the substation is found by multiplying the $10,000,000 by 75% for STS portion of $7,500,000.

All of the PODs that are not dual use are functionalized as 100% POD.

The substation fractions and net book value were applied on an individual basis. The customer-specific substation fractions and net book values are considered confidential information.

(c) Substation fractions for all DTS PODs are included without customer identifiers in the bill impact analysis provided as Appendix E to the AESO’s 2007 GTA. POD-specific cost information is considered confidential information.

(d) The impact of CIAC amounts on transmission costs functionalization is provided in Table 4 on page 52 of the 2006 Transmission Cost Causation Update provided as Appendix C to the AESO’s 2007 GTA.
Preamble: 4.3.2 Bulk Transmission System Cost Classification

The AESO states:

A significant portion of the analysis completed for the Transmission Cost Causation Update involved the “more thorough review of all those lines comprising the bulk system” required by Direction 4C of Decision 2005-096. PS Technologies first interviewed AESO system planners to discuss transmission paths, requirements to upgrade the bulk transmission system in different areas of Alberta, and causes of maximum stress on bulk transmission lines. This qualitative review was followed by a quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL).

Reference: Section 4 – 2007 Rate Design, Page 8 of 53.

Request:

(a) Please provide details of the interviews between PS Technologies and AESO system planners to “discuss transmission paths, requirements to upgrade the bulk transmission system in different areas of Alberta, and causes of maximum stress on bulk transmission lines.”

(b) Please confirm that the causes of maximum stress on bulk transmission lines in service in 2006 may be different and occur at different times than the causes of maximum stress and timing of that stress when the original approvals were obtained to construct the transmission lines currently in service. If no, please give a full explanation.

(c) Please confirm that any proposed “requirements to upgrade the bulk transmission system” that were discussed with transmission planners are for transmission assets that are not currently in TFO rate bases nor will be by the end of 2007 (i.e. the test year for the AESO tariffs). The review of discussions with transmission planners should, at a minimum, include the transmission paths identified in Table 1 of the 2006 Transmission Cost Causation Update. If no, please identify any exceptions.

(d) In deciding on the use of NCP, how much weight was given in these discussions with planners to transmission lines which will be in service in 2008 and beyond? Please confirm that these forward looking discussions would normally be considered part of a marginal cost study? If no, please provide a full explanation.

(e) Did AESO staff preparing this application conduct their own independent interviews with AESO system planners separate from PS Technologies? If yes, Please provide the same information as requested in (a) through (d) above.
(f) Please provide a full explanation for why the “quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL)” was conducted using AIL loads rather than AIES loads, given that behind-the-fence generation acts to reduce the amount of load that is seen at the interface with the AIES.

(g) Did the AESO attempt to determine if the quantitative analysis of the relationship between loading on individual bulk transmission lines and total Alberta Internal Load or AIES Load in the 2006 Transmission Cost Causation Update was similar to the causes and timing of maximum stress 5 to 15 years earlier or will be similar to the causes and timing of maximum stress 5 to 15 years in the future using planning models? If yes, please provide a summary of the comparison.

(h) Please confirm that the quantitative analysis left non-firm exports and DOS loads in the load flows. If no, please explain how these loads were removed from the analysis.

(i) Does the AESO agree that in any hour when an opportunity export is allowed that the 240 kV north south transmission system cannot be stressed to the maximum? If no, please give a full explanation.

Response:

(a) Please refer to the response to Information Request ADC.AESO-003 (d).

(b) The cause and timing of maximum stress on bulk transmission lines in 2006 may or may not be different than the cause and timing of the anticipated maximum stress at the time of the addition of the transmission line, depending on the line being considered. No study has been conducted to try to ascertain the original rationale for the addition of individual transmission facilities.

(c) The interviews with the transmission planners were conducted to identify constraints that the planners are currently working on. The alleviation of a constraint may not always require a major transmission addition. The alleviation of a constraint may include some small projects such as, for example, alleviating a clearance constraint in a span of existing line which results in an increased thermal rating for the line that is already in rate base. However, the AESO agrees that the majority of capital additions to address the constraints discussed with transmission planners would not be included in TFO rate bases prior to the end of 2007.

(d) The question is based on the premise that transmission planning has changed such that future additions are being made based on different rationale than past additions. Transmission planning criteria remain fundamentally the same as in the past. The integration of all past decisions, and the resulting capital additions, results in the embedded cost of the transmission system currently in place. The original Transmission Cost Causation Study and the 2006 Transmission Cost Causation Update are studies considering the embedded cost of the system as currently in place and currently utilized. A marginal cost study generally considers costs arising out of current decisions without regard for the existing costs already in place.

(e) No, although findings and conclusions of the study were reviewed with AESO system planners.
(f) The AIL is used because it is public information that is easily accessible on the AESO website.

(g) No. Please refer to part (d) above.

(h) Confirmed. Please refer to pages 13 and 14 of the 2006 Transmission Cost Causation Update (provided as Appendix C to the AESO’s 2007 GTA filed on November 3, 2006) for information on DOS, imports, and exports and their impact on the analysis.

(i) No. The AESO will allow opportunity exports up to the maximum established by the SOK-240 limit (a measure of loading on the north south line defined in OPP 304), barring any other export-related constraints. In other than high Alberta loading periods (Alberta load above 7,800 MW in summer or 9,000 MW in winter), exports are typically limited by SOK constraints.

During the high Alberta loading periods, exports are limited by other constraints such as steady-state voltage and voltage stability. The limits during these times are listed in Tables 3 and 4 of OPP 304 in the AESO’s Operating Policies and Procedures.
Preamble:
The AESO states:

Contrary to the expectation expressed during the AESO’s 2005-2006 GTA hearing, the Transmission Cost Causation Update found that there was very weak correlation between individual bulk line loading and total AIL. Based on metered data for the 8,760 hours in 2005, the load over all seventy-nine 240 kV bulk transmission lines in Alberta (weighted by line length) showed only an 8% correlation with AIL. In response to concerns about basing material conclusions on a single year’s data, the analysis was repeated using metered data for the 8,760 hours in 2004, resulting in bulk line load showing a somewhat lower 1% correlation with AIL.

Additional weighted and unweighted analysis incorporating net book value and percentage of thermal line rating provided correlations from -3% to +18% for 2005 data, and from -3% to +11% for 2004 data. Detailed review of the line data also showed that:

- None of the 240 kV lines experienced their monthly peaks during the times of AIL monthly peaks.
- During the hour of annual AIL peak, lines were loaded at about 60% of their annual peak load on average.
- During the hour of annual AIL peak in 2005, only four of the seventy-nine 240 kV lines were loaded at 90% or more of their annual peak. In 2004, only five of the lines were loaded at 90% or more.”

Reference: Section 4 – 2007 Rate Design, Page 8 of 53.

Request:

(a) In arriving at the 8% correlation noted in the preamble, did the AESO look for correlations between line loadings and AIES peaks, or only AIL peak loads? If yes, please provide the results of that analysis. If not, why not?

(b) Please provide the analysis and all supporting details in excel spreadsheet format of the additional “weighted and unweighted analysis incorporating net book value and percentage of thermal line rating” that provided correlations from -3% to +18% for 2005 data, and from -3% to +11% for 2004 data.

(c) How many 240 kV lines experienced monthly peaks during on-peak hours where the on-peak is defined as 8 AM to 8 PM? Of those which did peak during these on-peak hours, how many months did these 240 kV lines peak during on-peak hours (by transmission line and on average)?

(d) Did the AESO conduct analysis of correlations of line loadings for more than the one hour of AIES peak load? For example, did the AESO examine the likelihood that a peak
line loading might correlate with the top 10 peaks in any given month? What about the correlation that the line would peak in one of the on-peak periods identified by intervenors as potential on-peak periods in the AESO 2006 GTA?

Response:

(a) The correlation factors were determined on the basis of line loading and AIL. AIL was used because AIL is publicly available information that is already accessible on the AESO website.

(b) Please refer to the response to Information Request PWX.AESO-16 (b).

(c) For the 2004 metered data, transmission lines experienced their peak flows during on-peak hours (8 AM to 8 PM – 7 days/week) 6.8 months out of 12 months on average. There were 6 lines that never experienced peak flow during on peak hours, and there were 8 lines that always experienced peak flow during on peak hours. The following chart shows additional intermediate data for the frequency at which lines experienced peak flow during on peak hours for 2004.

![Frequency that Peak Line Loading Occurs during Peak Hours](chart.png)

This same data was also reviewed month by month. The following chart shows the percentage of lines that experience peak flow during on peak hours by month.
For 2005 meter data, transmission lines experienced their peak flow during on peak hours (8 AM to 8 PM – 7 days/week) 6.7 months out of 12 months on average. There were 7 lines that never experienced peak flow during on peak hours, and there were 9 lines that always experienced peak flow during on peak hours. The following chart shows additional intermediate data for the frequency at which lines experienced peak flow during on peak hours in 2005.
This same data was also reviewed month by month. The following chart shows the percentage of lines that experience peak flow during on peak hours by month.

Please note that peak flow on a transmission line has been used as a proxy for maximum stress on the system. However, maximum stress can occur for a number of reasons (please refer to section 2 of the 2006 Transmission Cost Causation Update provided as Appendix C to the AESO’s 2007 GTA) and therefore, maximum stress on the system is not synonymous with peak line load.
(d) The correlation analysis includes line load, and AIL load, in every hour. The correlation factor provides an indication of whether the line load moves with the AIL load (positive correlation factor) or if the line load moves in opposite direction from the AIL load (negative correlation factor). If the correlation factor is zero, then the line load is independent of the AIL load. Please refer to page 16 of the 2006 Transmission Cost Causation Update (provided as Appendix C to the AESO’s 2007 GTA filed on November 3, 2006) for an example of a line where line loading is quite independent of AIL load.
Preamble: The AESO states:

Second, there are excursions outside that band in almost every hour of the day. For example, lines 917L (Janet to East Calgary) and 936L and 937L (Langdon to East Calgary) have profiles with significantly higher-than-average loading in the late afternoon and lower-than-average loading in the pre-dawn early morning. In contrast, lines 910L and 914L (Edmonton to Red Deer), 916L (Sarcee to East Calgary), and 9L59 (Sheerness to Battle River) have the reverse profile: higher-than-average loading in the pre-dawn early morning and lower-than-average loading in the daytime. Other lines have yet other profiles: line 995L (Brazeau to Benalto) has its highest loading in the pre-noon daytime hours.


Request:

Please provide the data in Excel spreadsheet format that supports the assertions in the preamble.

Response:

The data was posted on the AESO website shortly after the filing on December 13, 2006 of the additional analysis of bulk system data provided as Appendix D to the AESO’s 2007 GTA. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path Tariff > Current Applications > 2007 Tariff Application > Additional Information. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.
Preamble: The AESO states:

Stakeholders also suggested that the bulk transmission system was designed to accommodate loading under contingency conditions, whereas the analysis in the Transmission Cost Causation Update reflects normal operating conditions. Although planning decisions do accommodate contingency conditions, in the AESO’s experience cost classification is not based on contingency conditions. Classification of costs is typically based on current usage of the system, and is frequently based on recent historical pattern (including those established through load research, for example). The AESO is not aware of jurisdictions which classify costs based on system usage under contingency conditions.


Request:

(a) Please provide a description of the expertise and training of the AESO or its consultants in conducting cost of service studies, including functionalization, classification and allocation of costs.

(b) Please provide the references relied on to support the statement that “Classification of costs is typically based on current usage of the system, and is frequently based on recent historical pattern”, including industry articles, board or commission decisions and cost of service studies conducted in other jurisdictions.

(c) Identify all jurisdictions and cost of service studies known to the AESO, if any, that include cost causation as at least one determinant of cost of service and where cost causation includes an examination of the historical drivers for those costs.

(d) Please confirm that if a customer was a key driver for the need for a new transmission facility, and then the allocation method is changed due to adjustments in how the system is operated, in a manner that results in a significantly reduced cost burden for that customer, then that customer is potentially getting an unfair benefit? If no, please provide a full explanation.

Response:

(a) Please refer to the attached curriculum vitae of Arnie Reimer of PS Technologies, Inc., who completed the 2006 Transmission Costs Causation Update under contract to the AESO.

(b) The statement was based on the AESO’s experience and understanding of the basis for cost classification. Please refer to the response to Information Request IPCAA.AESO-012 (b) for additional information.
(c) The AESO has not surveyed other jurisdictions to determine which, if any, include historical cost drivers in cost causation studies.

(d) Generally a single customer is not a key driver for a new bulk transmission facility. Bulk system components, by definition, serve multiple customers.

The AESO suggests changes to allocation methodologies do occur from time to time and do result in changes to costs attributable to customers. For example, in the mid-1980s the allocation of generation and transmission costs in Alberta changed from a 1 CP basis to a 3 winter/9 non-winter basis. Such changes are generally considered appropriate if they reflect current causation related to the costs being allocated.
Preamble: The AESO states:

Some stakeholders suggested that recent usage of the bulk system does not represent either the expectations under which the system was originally planned or future usage after completion of system expansions planned in the next decade (such as the 500 kV North-South Reinforcement, for example). The AESO generally agrees that the nature of the bulk system has changed from the era of centrally-planned generation to the current market-based model, and the location of generation with respect to load has affected usage patterns for the bulk lines. However, some of the lines which do not follow the system load profile date from the time of centrally-planned generation: lines 910L and 914L (Edmonton to Red Deer), 9L59 (Sheerness to Battle River), and 995L (Brazeau to Benalto), for example. Furthermore, the AESO’s recent 10-Year Transmission System Plan and 20-Year Transmission System Outlook both anticipate additional generation in many areas of Alberta. Current usage of the transmission system under today’s market-based model is therefore expected to be representative of future usage. The AESO therefore considers that recent usage of the bulk system is an appropriate basis for cost classification for rate design.


Request:

(a) Please provide the analysis and supporting information that demonstrates “some of the lines which do not follow the system load profile date from the time of centrally-planned generation: lines 910L and 914L (Edmonton to Red Deer), 9L59 (Sheerness to Battle River), and 995L (Brazeau to Benalto)”.

(b) Regarding the statement that “Current usage of the transmission system under today’s market-based model is therefore expected to be representative of future usage”, please confirm that this would mean that the amount of Calgary area generation would remain in the same proportion to Edmonton area generation. If no, provide a full explanation. If yes, please provide the support from current transmission plans of the AESO to confirm this statement.

(c) Please provide transmission planning evidence that other generation developments will remain at similar levels compared to other areas of the province in current circumstances compared to the future for areas such as Ft. McMurray and Southwest Alberta.

Response:

(a) Please refer to the response to Information Request PWX.AESO-16 (b), which shows that 910L, 914L, and 9L59 all have negative correlation coefficients. Other lines such as 995L do have positive correlation coefficients but exhibit near-maximum peaks in the
mid-morning hours. The hourly metered data for all lines was posted on the AESO website shortly after the filing on December 13, 2006 of the additional analysis of bulk system data provided as Appendix D to the AESO's 2007 GTA. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path Tariff > Current Applications > 2007 Tariff Application > Additional Information. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.

(b-c) The statement was made to reflect the fact that transmission planning criteria and other drivers affecting utilization of the transmission system are expected to remain fundamentally the same in the future. This statement does not mean that the transmission system remains geographically static and simply grows proportionally in all regions.
Preamble: The AESO states:

Although the AESO supports the Transmission Cost Causation Update as an appropriate and sound analysis of transmission system cost functionalization and classification, some stakeholders continued to question the validity of its approach. The AESO therefore retained National Economics Research Associates (NERA) of Los Angeles, California, to conduct a review of the bulk system analysis and conclusions in the Update. On the whole, NERA found the proposed functionalization and classification reasonable, although they did offer suggestions for a few refinements to the rate design itself. The AESO posted the NERA assessment report on its website, but did not consult with stakeholders on NERA’s findings due to lack of time before filing this application. The AESO also does not rely on the NERA review as part of its evidence and therefore has not filed the NERA report as part of this application.


Request:

(a) Please provide a copy of the review conducted by NERA.

(b) Please confirm that the AESO gave no weight to this report in developing its final recommended tariff.

(c) Please explain why the AESO did not rely on the NERA review as part of its evidence?

(d) Please identify the recommendations in the NERA report that the AESO agrees with and those that the AESO rejects. Provide full explanations for the AESO’s position on each NERA recommendation.

(e) Does the AESO intend to have a NERA representative available for cross-examination?

(f) For the authors of the NERA report, please provide their experience and qualifications, including training, in conducting cost of service studies and determining cost causation.

Response:

(a) Please refer to the response to Information Request BR.AESO-001.

(b-c) Please refer to the response to Information Request ADC.AESO-016.

(d) The AESO agrees with most recommendations in the NERA assessment.

However, as discussed in the response to Information Request IPCAA.AESO-013 (c), the AESO is not convinced it is inappropriate to use a factor as applied in the 2006 rate
design to reduce the demand classification of bulk system costs, especially if bulk system costs are to be billed on the basis of coincidence with system peak.

The AESO is also not convinced the definition of billing capacity should be modified to reduce the 90-percent factor applied to contract capacity and the highest demand in the past 24 months. NERA suggests such a reduction could make the highest metered demand in more months a potential factor in calculating interconnection charges. The AESO considers the 90-percent factor appropriate in consideration of the underlying long-term fixed nature of the transmission system.

(e) No. Please refer to the response to Information Request ADC.AESO-016.

(f) Please see the attached *curricula vitae* for the NERA project team.
Preamble: The AESO states:

After concluding that recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective, the AESO examined alternatives for recovery of bulk system costs. The AESO also invited stakeholders to suggest an appropriate basis for recovery of bulk system costs. Various recommendations were put forward, ranging from continuing coincident peak recovery for reasons other than costs causation, to expanding the peak demand period to additional coincident hours or a specified time of day, to recovery on an energy basis. The AESO considered these suggestions and concluded at that time that recovery of demand-related bulk system costs on billing capacity is the most appropriate approach.


Request:

Please identify all the reasons why “expanding the peak demand period to additional coincident hours or a specified time of day, to recovery on an energy basis” was rejected by the AESO.

Response:

Please refer to the response to Information Request BR.AESO-002 (a).
Preamble: The AESO states:

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


Request:

(a) Please provide the data and working papers to support the statement “Loading on the bulk transmission system varies from 97% to 103% of average on an hourly basis, and from 93% to 111% of average on a monthly basis”.

(b) Please confirm that using averages of averages (whether hourly or for a month), eliminates much of the variability that occurs in the usage of lines during the course of the year. If not confirmed, please provide a full explanation.

Response:

(a) The data was posted on the AESO website shortly after the filing on December 13, 2006 of the additional analysis of bulk system data provided as Appendix D to the AESO’s 2007 GTA. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path Tariff > Current Applications > 2007 Tariff Application > Additional Information. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.

(b) Averaging data both eliminates hour-to-hour and month-to-month variability and reveals patterns that are obscured by such variability. The AESO notes that the correlation between individual bulk line loading and system load was analyzed based on detailed hourly data as presented in the 2006 Transmission Cost Causation Update. The findings in the Update were the primary basis for the conclusions reached. The examination of bulk line loading was later completed based on average data to determine if patterns might exist which were not suggested by the correlation analysis, which confirmed these findings.
Preamble: The AESO states:

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.


Request:

(a) Please confirm that costs of the bulk system could be analyzed (rather than recovered) based on the coincidence of loads in a region with bulk line loading in the region without violating the Electric Utilities Act. If no, please provide a full explanation.

(b) Does the AESO agree that the results of an analysis of the coincidence of loads in a region with bulk line loading in the region could be incorporated in a cost of service study and then in rate design without necessarily requiring tariffs that vary by geography? If no, please provide a full explanation.

(c) Does the AESO agree in principle that at least some cost responsibility is born by both summer peaking and winter peaking transmission lines using the 12 CP method assuming the transmission lines peak during the coincident peak hours? If no, please provide a full explanation.

(d) Regarding part (c) above, if a reasonably wide range of on-peak hours throughout the year were used for allocating costs rather than the 12 CP method, would the AESO agree that there would be cost responsibility attributed to both summer and winter peaking transmission lines? If no, please explain.

Response:

(a) The AESO agrees that the Electric Utilities Act (EUA) does not restrict or prevent the approach used in the analysis of transmission system cost causation. However, cost recovery generally follows cost causation, and the EUA states (in paragraph 30(3)(a)) that the rates of the AESO cannot differ as a result of the location of the AESO’s customer. If differences arising as a result of a regional analysis could not be implemented in rates, the AESO considers completing such a regional analysis would have little value.

(b) The AESO accepts that such an analysis and outcome is conceptually possible, but expects it would provide rates similar to those based on the analysis provided in the 2006 Transmission Cost Causation Update and on the proposed average and excess demand allocation methodology.
First, loads within a region affect the bulk transmission system within the region, between regions, and within other regions, as discussed in the responses to Information Requests ADC.AESO-005 (c) and CG.AESO-005 (a). Costs from all regions must therefore be attributed to load within each region in some manner, and loads within a region would share to some extent in the cost responsibility for the bulk transmission system in all regions of the province.

Second, the AESO expects that, to satisfy the “postage stamp” rates requirement of the Electric Utilities Act, the results of regional analyses would be combined in some manner to create a final weighted average cost classification and rate design.

The AESO suggests that its proposed average and excess method utilizing the length-weighted bulk transmission line load factor would provide similar results. The averaging over all lines reflects an individual load’s impact on overall line loading throughout the province, and weighting by line length reflects the relative contribution of different lines to the overall cost of the bulk transmission system.

(c) The AESO does not agree that bulk transmission line loading correlates with system peaks, as discussed at length in section 4.3.2 of the AESO’s 2007 GTA. However, if such correlation did exist, in both summer and winter months, then a 12 coincident peak methodology would allocate at least some costs with respect to both summer peaking and winter peaking lines.

(d) The AESO does not agree that bulk transmission line loading correlates with any range of “on-peak” hours, as discussed in the response to Information Request ADC.AESO-005 (d). However, if such correlation did exist, in both summer and winter months, then an “on-peak” methodology would allocate at least some costs with respect to both summer peaking and winter peaking lines.
Preamble: The AESO states:

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.


Request:

(a) Please confirm that after a customer has established a significant peak under the NCP method, that no hours that peak at levels below that peak have any impact on the costs incurred by that customer? If no, please provide a full explanation.

(b) Please confirm that for summer peaking or winter peaking transmission lines, only the demands in the summer or winter months, respectively, are relevant to causing costs on the bulk system? If no, please provide a full explanation.

(c) Considering the response to (b) above, please provide the justification for the use of a 24 month ratchet for transmission lines that may have many months that do not set peaks and do not cause costs to be incurred.

(d) Provide the entire justification for the use of “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” for billing bulk system costs.
Please provide any statistical evidence to demonstrate that the use of NCP with ratchets and 90% of contract capacity provides a more accurate allocation of bulk transmission costs than the use of various on-peak methods or the 12 CP method.

Please confirm that NCP discourages load shifting from on peak to off peak periods since it charges a customer the same amount for the same load regardless of when they use electricity. If no, please provide a full explanation.

Please confirm that the AESO has decided to give no weight to the historical reasons why costs were incurred. If no, please provide a full explanation and describe the weight that the AESO has placed on historical cost causation.

Please confirm that the transmission system is not typically planned only for flows on the system under normal operating conditions but transmission planners also plan the system for N-1 and N-2 contingencies and under those conditions examine concerns such as voltage stability, thermal limits and dynamic stability limits. If no, please provide a full explanation. If yes, please explain if any of the analysis undertaken in the Transmission Cost Causation study took into account N-1 and N-2 contingencies that stress the transmission system and if so, how this was accomplished.

Response:

(a) Confirmed for hours within a billing period, but not confirmed for hours in subsequent billing periods. Please refer to the response to Information Request EnCana.AESO-018 (b) for additional information.

(b) Confirmed, when the loading on the summer peaking or winter peaking transmission line is significantly above the loading in other seasons. If loading is similar or varies within a relatively narrow band during the year, as is illustrated for many bulk transmission lines in Figure 4.3.5 on page 10 of section 4 of the AESO's 2007 GTA, then loading in all or many months may be relevant to cost causation.

(c) The reasons for using a demand ratchet are provided in the response to Information Request CG.AESO-006 (b). Given that transmission line loading is similar or varies within a relatively narrow band during the year as discussed in part (b) above, a customer's demand in any month may contribute to bulk transmission line peaks. Demand ratchets appropriately allocate the associated costs to the customer.

The billing capacity ratchet period is 24 months in the AESO's current DTS rate, and was approved in EUB Decision 2005-096 to provide “a reasonable balance between customer flexibility and revenue stability.” (p 30) The AESO proposes that a 24-month ratchet period continues to remain appropriate for similar reasons.

(d) All three components of billing capacity are appropriate for the recovery of bulk transmission system costs. As discussed in section 4.3.2 of the AESO's 2007 GTA, it is likely that some, but not all, transmission system components will be at or near maximum loading conditions in every hour of the day and every month of the year, and billing on the highest metered demand in the billing period reflects such a finding. The reasons for including a demand ratchet component are discussed in part (c) above. Finally, a contract capacity component is included to reflect the influence of contract capacity on transmission system forecasting, planning, and operation.
(e) Please refer to the response to Information Request ADC.AESO-004 (a-e).

(f) Please refer to the response to Information Request ADC.AESO-007 (a-c).

(g) Confirmed. As discussed on pages 9-11 of section 4.3.2 of the AESO's 2007 GTA, the AESO considers that recent usage of the bulk transmission system is an appropriate basis for cost classification for rate design.

(h) Please refer to the response to Information Request IPCAA.AESO-010 (b-c).
Preamble: The AESO states:

…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.


Request:

(a) Please provide the evidence supporting the statement that the bulk system contains relatively equal amounts of line and substation equipment.

(b) Please provide a complete analysis, including supporting schedules, to support the statement that about one-quarter of TFO revenues requirements are OMA costs. Also, identify which of those OMA costs are fixed in nature (unaffected by short-term variation in energy consumption on the transmission system) compared to OMA costs, if any, that do vary with energy consumption.

Response:

(a) The statement that the bulk system contains relatively equal amounts of line and substation equipment is based on the observation of the net book value of the bulk system. Approximately one half of the net book value of the bulk system consists of transmission lines and the other half of substations.

(b) The reference “OMA costs account for about one-quarter of TFO revenue requirements” was not intended to represent an exhaustive study of OMA costs as a percentage of total TFO revenue requirements. Therefore, there is no detailed analysis and supporting schedules beyond the observation that “about one-quarter” of the TFOs’ revenue requirements consist of the cost of operations. For example, if you refer to the AltaLink 2004 to 2007 GTA, Schedule 4.1 shows forecast operations costs of $51.4 million in 2007, and forecast revenue requirement of $216.2 million. When the forecast operations cost is divided by the total revenue requirement, the result is 23.8%. Similarly, in ATCO Electric’s 2003 to 2005 GTA, Schedule 4-B-1 shows forecast operations costs of $45.7 million in 2005 and a total revenue requirement of $165.5 million. In this case, operations represent 27.6% of the total revenue requirement. Further information on TFO revenue requirements is available from the TFO applications.
Preamble: The AESO states:

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.


Request:

(a) Please confirm that the 30 projects are relatively recent projects and that the results of the cost function are applied to the embedded costs of all PODs for all time periods that facilities were included in the TFO rate bases.

(b) Please also provide the percentage of MW and costs represented by this sample relative to the total MW and costs of all POD costs being classified.

(c) Please provide the supporting calculations to the cost function in Excel spreadsheet format.

(d) Please provide a rate comparison between the proposed cost function and the cost function supporting the currently approved POD costs at 2, 4, 6, 8, 10, 15, 20 and 25 MW levels of DTS capacity.

Response:

(a) In the AESO’s 2005/2006 GTA the AESO proposed to create a tighter link between rates and the AESO’s customer contribution policy particularly the maximum investment level. The EUB noted in Decision 2005-096 “that cost and not revenue is the appropriate starting point for establishing an investment policy. “ (page 56 of Decision 2005-096) and based its maximum investment level decision upon that principle. In an effort to uphold the EUB’s principle and due to a lack of clear POD-related cost data for cost allocation purposes the AESO initiated a study that would collect actual POD data that would provide a more robust data set in which to base cost allocation and investment recommendations and also allow interested parties to scrutinize the data and raise the
level of transparency and understanding of the POD related cost discussion. The AESO acknowledges that the data sample is limited with only moderate correlation. As outlined in Section 6.5.3 page 24 of the Application the AESO conducted a reasonableness test on the results of the 30 project data sample reproduced below:

In addition to utilizing the Transmission Cost Causation Study data, the AESO tested the reasonableness of these results as outlined below.

The first test involved a review of the average cost function of the Transmission Cost Causation Study. The AESO first reduced the TFO POD data collected for the Transmission Cost Causation Study to only those PODs where the vintage was known (approximately 109 PODs). The project costs were then escalated to current day dollars. Although the data did not include enough detail to validate that only standard facilities were included or that interconnections were reasonably representative of current standards, the AESO performed a simple linear regression analysis of the interconnection projects included. The resulting average costs equation was:

Average TFO Data Costs = $5.074 million + ($0.115 million/MW × DTS Capacity)

The TFO data set represented by the equation above has a regression coefficient of 0.18, less than that of the 30-greenfield project data set. However, this equation is reasonably close to the greenfield project equation (Equation 1), which the AESO submits provides support for the cost function derived above.

(b) As noted in the referenced text, the cost function is based on “30 projects representing a total DTS capacity of 516.7 MW and total project costs of $213.2 million....” The following comparison uses data from Schedules 5.3 and 5.9 in section 5 of the AESO’s 2007 GTA.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Sample</th>
<th>Total GTA</th>
<th>Ratio Sample/GTA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of PODs</td>
<td>30</td>
<td>485</td>
<td>6.2%</td>
</tr>
<tr>
<td>DTS Capacity (MW)</td>
<td>516.7</td>
<td>8,979.0</td>
<td>5.8%</td>
</tr>
<tr>
<td>POD Costs ($ 000 000) (Note)</td>
<td>$213.2</td>
<td>$596</td>
<td>35.8%</td>
</tr>
</tbody>
</table>

Note: For the sample, POD costs represent replacement cost new for the 30 PODs, while for the Total GTA, POD costs represent net rate base (original cost less depreciation and customer contributions) for the 485 PODs.

(c) The calculations are included in the Customer Contribution Policy Working Data provided as Appendix G to the AESO’s 2007 GTA, in the tab labeled “All Projects” in the Excel workbook.

(d) The currently approved POD cost function, was determined based on a simple linear regression performed on the DTS Capacity and Project Cost data provided in Table 6.1.1 in section 6 of the AESO’s 2005/2006 General Tariff Application. The resulting equation is:

Cost function (currently approved) = $2,500,000 + ($100,000 x DTS Capacity)

The proposed cost function is:
Cost function (proposed) = $947,000 +
($621,000/MW x first 7.5 MW of DTS Capacity) +
($154,000/MW x DTS Capacity above 7.5 MW)

The following table illustrates a comparison of the two cost functions at various DTS Capacities:

<table>
<thead>
<tr>
<th>DTS Capacity</th>
<th>Current Cost Function</th>
<th>Proposed Cost Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 MW</td>
<td>$2,700,000</td>
<td>$2,189,000</td>
</tr>
<tr>
<td>4 MW</td>
<td>$2,900,000</td>
<td>$3,431,000</td>
</tr>
<tr>
<td>6 MW</td>
<td>$3,100,000</td>
<td>$4,673,000</td>
</tr>
<tr>
<td>8 MW</td>
<td>$3,300,000</td>
<td>$5,681,500</td>
</tr>
<tr>
<td>10 MW</td>
<td>$3,500,000</td>
<td>$5,989,500</td>
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<tr>
<td>15 MW</td>
<td>$4,000,000</td>
<td>$6,759,500</td>
</tr>
<tr>
<td>20 MW</td>
<td>$4,500,000</td>
<td>$7,529,500</td>
</tr>
<tr>
<td>25 MW</td>
<td>$5,000,000</td>
<td>$8,299,500</td>
</tr>
</tbody>
</table>
Preamble: The AESO states:

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


Request:

Please confirm that the analysis undertaken by the AESO provides a cost function that is reflective of the costs caused by a customer interconnection at a POD for those recent projects included in determining the cost function but not necessarily for all PODs (since only a small sample of PODs were examined and they were not randomly selected but were largely selected from recently constructed PODs). If no, please provide a full explanation.

Response:

The AESO agrees that the cost function was based on data for recently-constructed substations, but notes that the cost function was tested for reasonableness using additional data as discussed on pages 24-26 of section 6 of the AESO’s 2007 GTA. The AESO also does not expect that the proportion of fixed to demand-related costs for a substation has varied materially over time. It is this proportion that is significant in the cost function, since the proportion determines the relative classification of POD-related costs into customer- and demand-related components (in Table 4.3.6 on page 14 of section 4 of the Application).
Preamble: The AESO states:

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

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

Reference: Section 4 – 2007 Rate Design, Page 14 to 53.

Request:

(a) Please confirm that revenues from the Regulated Generating Unit Connection Costs (“RGUCC”) Charge in the STS tariff are netted against the entire wires-related cost of service per Schedule 5.2 of Section 5 in the Application. If no, please indicate how RGUCC Charges are netted to the various functions and classifications of costs. Confirm that Primary Service Credits are also netted against the entire wires-related cost of service per Schedule 5.2.

(b) Provide an explanation and justification for the way in which RUGCC Charges are treated by the AESO in the cost causation study. For example, if RGUCC Charges are largely related to POD costs of generating units, is it more appropriate for only the POD costs to be offset by revenues from RGUC Charges? Why are Primary Service Credits not charged only to POD costs?

Response:

(a) Confirmed for both RGUCC Charges and Primary Service Credits.

(b) The treatment of Regulated Generating Unit Connection Costs remains the same in the 2006 Transmission Cost Causation Update as in the original Transmission Cost Causation Study filed on January 31, 2005 as Appendix B to the AESO’s 2006 GTA. As explained in the AESO’s response to Information Request ENCANA.AESO-025 (b) in that proceeding, “Where a TFO owns POS facilities that provide service to previously regulated generation, those facilities were considered Bulk. Likewise, the revenue from
the RGUCC charge offsets the cost of the Bulk system.” This effect of this treatment is included in Revised Table 22 on page 53 of the 2006 Transmission Cost Causation Update provided as Appendix C to the AESO’s 2007 GTA.

The RGUCC charges appropriately reduce the bulk system function in which property related to regulated generating unit interconnections is functionalized. The actual revenue offset received from the RGUCC charges should therefore reduce total wires costs, and as a result reduce each wires cost function proportionately. This is achieved by including RGUCC charges in the revenue offsets classified in Schedule 5.3 in section 5 of the AESO’s 2007 GTA.

Primary Service Credits represent less than 1% of total wires costs. These and the other relatively small amounts which comprise DTS revenue offsets have been classified with total wires costs in all prior tariffs of the AESO and its predecessors. Given the magnitude of the revenue offsets in comparison to the time and resources that would be required to compete a detailed review of each offset’s classification, the AESO suggests continuing past practice is reasonable.
Preamble:
The AESO states:

Based on additional investigation conducted as part of the Transmission Cost Causation Update and discussed thoroughly in section 4.3.2 of this application, the AESO proposes that bulk system demand-related costs be recovered through a non-coincident demand charge, and more specifically based on billing capacity. Recovery of bulk system costs in this manner results in similar recovery of bulk system and local system costs — namely, on an 81.5% demand- and 18.5% energy-related basis for the bulk system, and on an 82.5% demand- and 17.5% energy-related basis for the local system. Such an outcome is reasonable, considering that both the bulk system and the local system provide service to the same transmission customers, that costs are aggregated over all customers, and that both functions were classified using simple minimum system analyses.


Request:

(a) Please confirm that the bulk system does not serve the same transmission customers as the local system in cases such as export loads, loads served directly from the bulk system and loads served by generation connected to the loads by local transmission lines. If no, please provide a full explanation.

(b) Please confirm that all costs are not aggregated equally over all customers, such as merchant transmission customers, exports and DOS loads. If no, please provide a full explanation.

(c) Please confirm that it is a common cost of service practice to deal with opportunity customers in two steps:

(1) to allocate transmission costs only to firm customers since non-firm customers do not cause fixed costs to be incurred; and

(2) then to design a contribution to fixed costs for non-firm customers in the rate design process.

If no, please provide a full explanation.

Response:

(a) The physical facilities comprising the bulk system are generally considered to be utilized in providing transmission service to all customers, both in moving power from generation surplus regions to load regions and in providing support between regions during contingencies and special operating conditions. The physical facilities comprising the local system would sometimes not be utilized in providing transmission service to a
specific customer, as some customers are physically interconnected through 240 kV facilities which would usually be considered part of the bulk, rather than local, system.

However, system access service through a connection to the transmission system provides access to exchange electric energy and ancillary services, and is not differentiated by the actual physical system facilities associated with a specific service. Access to exchange electric energy and ancillary services is provided to all transmission customers, regardless of the actual interconnection voltage. With respect to export services in particular, please refer to the response to Information Request PWX.AESO-008 (a-b).

(b) All costs recovered on a variable basis are recovered over all customers, where the costs are incurred in providing service to those customers. Costs recovered on a fixed basis are recovered from customers for whom transmission assets would be installed based on long-term service commitments, and generally exclude opportunity service customers.

(c) The AESO generally agrees, and adds that rates for opportunity customers also generally include variable components from the rates for firm customers. As well, opportunity service may also be provided under rates based on value of service or under negotiated rates.
Preamble: The AESO states:

However, in its 2006 GTA the AESO moderated the demand classification of the bulk system costs through an analysis of bulk line peak coincidence. This moderation was specifically questioned in Direction 4C of EUB Decision 2005-096. Some stakeholders questioned the specific approach adopted by the AESO in its 2006 rate design, sometimes even when those stakeholders supported a reduction to the demand-related (and corresponding increase to the energy-related) classification of bulk system costs. Stakeholders also suggested the AESO examine other approaches to cost classification, including the “average and excess method”.

Although the discussion in section 4.3.2 demonstrates that coincidence with system peak is not an appropriate basis for bulk system rate design, the AESO considers that the demand-related classification of the bulk system should be reduced to account for varying POD load factors and varying probabilities that individual POD loads will coincide with maximum stress on transmission system components.


Request:

(a) Do the stakeholders who suggested the AESO examine other approaches to cost classification including the use of the average and excess method currently support the use of the average and excess method? If yes, please indicate how many stakeholders the AESO is aware of that support its use.

(b) Does the AESO strongly endorse the use of the Average and Excess method or is the AESO attempting to accommodate stakeholder(s) recommendations?

(c) Please explain what is meant by “the demand-related classification of the bulk system should be reduced to account for varying POD load factors” and provide an explanation from cost of service principles or theory to support this reduction.

(d) Please confirm that the Average and Excess method assumes a linear relationship between coincidence factor and load factor, contrary to the Bary curve (as described by Constantine W. Bary in Operational Economics of Electric Utilities). If no, please provide a full explanation.

Response:

(a) Please refer to the response to Information Request IPCAA.AESO-021 (a). The AESO has not canvassed stakeholders to determine how many currently support the use of the average and excess demand method.
(b) The AESO considers that use of the average and excess demand method, together with the other components of the cost causation study and proposed rate design, satisfies the rate design principles outlined in section 4.2 of the AESO’s 2007 GTA more fully than other approaches. Please refer to the response to Information Request BR.AESO-002 (a) for additional information.

(c) Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-024 (a).

(d) Not confirmed. Although the average and excess demand method results in the average versus excess portions varying linearly with load factor (as discussed in the response to Information Request IPCAA.AESO-024 (b)), its application is not intended to predict coincidence with a system peak as was the purpose of the relationship between coincidence factor and load factor studied by Bary.

As explained in the response to Information Request EnCana.AESO-012 (b), “Since the various components of the transmission system experience peak loading at different times, it is not practical to measure or predict when a customer’s maximum load would coincide with the various transmission component peak loads. It is therefore appropriate to use the probabilistic method inherent in the average and excess demand approach and to allocate on an energy basis costs which are classified as demand-related.”

Please refer to the response to Information Request IPCAA.AESO-022 for additional information.
Preamble: The AESO states:

Allocating and recovering the majority of transmission system costs on a non-coincident peak basis may be most appropriate when customers have reasonably similar load factors. This is not the case for the transmission system, where 230 DTS PODs have load factors of 60% or more, 138 PODs have load factors between 40% and 60%, and 117 PODs have load factors below 40%. The “average and excess” method suggested by some stakeholders generally provides better recognition of variations in load factor, since it accounts for the increasing likelihood of an individual customer’s contribution to a peak system component demand with increasing load factor. This method also does not distinguish between customers based on timing of the customer’s load, which seems to appropriately reflect the AESO’s findings in its analysis of the transmission system.


Request:

(a) Please provide the data in Excel spreadsheet format that provides the support for the statement “230 DTS PODs have load factors of 60% or more, 138 PODs have load factors between 40% and 60%, and 117 PODs have load factors below 40%”.

(b) Please provide references from the cost of service literature that are relied on to make the statement that the “average and excess” method “generally provides better recognition of variations in load factor” and include to which method the average and excess method is being compared. Also, include all known references from industry recognized sources and evidence of other cost of service experts to support the statement.

(c) Please provide a discussion of the concerns expressed in the power industry literature (such as the inaccuracy of the assumption about a linear relationship between coincidence factor and load factor) about the use of the average and excess “demand” or AED method and comment on whether the AESO agrees with these concerns or not.

(d) Please confirm that the AED method has normally been proposed for classifying and allocating costs of generation, not transmission. If no, please provide a full explanation.

(e) Please confirm that in jurisdictions that have adopted the AED method for transmission, the adoption has been in conjunction with use of the AED method for generation. If no, please provide a full explanation and a list of jurisdictions where the AED method is in use for transmission facilities but not for generation facilities.
Response:

(a) The data was included in the Excel workbook providing the DTS Bill Impact Comparison by POD, filed as Appendix E to the AESO 2007 GTA on November 3, 2006. Please refer to the LF (Load Factor) column in that workbook.

(b) Please refer to the responses to Information Requests EnCana.AESO-012 (b) and IPCAA.AESO-024 (a-b).

The Process of Ratemaking by Leonard Saul Goodman (Public Utilities Reports, Inc., Vienna, Virginia, 1998, p 1069) states in reference to the average and excess demand approach, “This method tends to recognize the contribution to system peak by load factor, but does not distinguish between on-peak and off-peak loads with the same load factor. The average and excess method and the non-coincident class peak method may yield identical answers when there are no significant deviations among the class and system load factors.”

The average and excess demand approach is being compared to the non-coincident demand approach discussed in the text preceding the reference from the AESO’s Application. In Principles of Public Utility Rates by James C. Bonbright et al. (quoted in EnCana.AESO-012 (b)) and in The Process of Ratemaking (quoted above), the authors make similar comparisons between a non-coincident demand approach and the average and excess demand approach.

(c) The AESO understands concerns expressed about the use of the average and excess demand approach are:
- lack of recognition of load diversity (for example, between on-peak and off-peak loads);
- accuracy of probability assumptions underlying the methodology; and
- general controversy about the allocation of “joint costs”.

(i) Lack of recognition of load diversity — The Process of Ratemaking by Leonard Saul Goodman (Public Utilities Reports, Inc., Vienna, Virginia, 1998, p 1069) notes that the average and excess demand approach “does not distinguish between on-peak and off-peak loads with the same load factor.” Discussion of an alternate method (p 1070) suggests the average and excess demand method might not reflect “the diversity between class usage patterns in relation to the system as a whole.”

The AESO considers diversity concerns to be minimal in the allocation of transmission system costs in Alberta, as the discussion in section 4.3.2 of the AESO’s Application demonstrates that it is likely that some, but not all, transmission system components will be at or near maximum loading conditions in every hour of the day and every month of the year. There appear to be no significant on-peak and off-peak periods over the transmission system as a whole.

studies of the relationship between load factors and coincidence factors for
different used of service (air conditioning, water heating, elevator operation, etc.)
are required."

Accuracy concerns seem primarily related to the prediction of coincidence with
system loading. As noted above, it is likely that some, but not all, transmission
system components will be at or near maximum loading conditions in every hour
of the day and every month of the year, and concern with coincidence with a
specific peak load or peak period is not applicable.

(iii) **Allocation of “joint costs”** — *Principles of Public Utility Rates* by James C.
Bonbright et al. states (p 498) that capacity cost allocation is controversial
because “capacity costs, instead of being ordinary overhead costs, common to
different kinds of amounts of service, are joint costs — the costs of producing
services which are joint products when they are rendered at different periods of
time,” and (p 502), “This being the case, any apportionment of capacity costs,
say, as between morning service and evening service, or as between winter
service and summer service, or even as between all services rendered in one
year and all services rendered in the following year, is a partly arbitrary
apportionment from the standpoint of cost determination, however justified or
convenient or rational it may be from the standpoint of reasonable rate
determination.”

The AESO generally agrees with this concern. Despite a justifiable basis for the
average and excess demand approach (as discussed in response to Information
Request EnCan.AESO-012 (b)), other approaches can also be justified. There
is no single correct method for allocating such joint costs, as is clear from the
variety of methods described in the literature. However, for its 2007 GTA the
AESO considers the average and excess demand approach satisfies the rate
design principles applicable to the AESO’s tariff.

(d-e) Confirmed. The *Electric Utility Cost Allocation Manual* by the National Association of
of the A&E [average and excess] method for allocating transmission costs is typically
employed for consistency when production costs are allocated on the same basis.”
Preamble: The AESO states:

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

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


Request:

(a) Please provide the details in Excel spreadsheet format to support the statement that the “length-weighted average 240 kV line load factor was 50.0% in 2005 and 47.3% in 2004”.

(b) Please provide the details in Excel spreadsheet format to support the statement that the “the average line load factor is likely representative of both bulk and local systems due to the similarity of the systems.” Include an analysis of the load factors for both systems.

(c) Discuss all of the significant differences between bulk and local systems and include descriptions of tie lines that primarily exist at the bulk system level, customers served directly at 240 kV, interconnections with generators at the bulk system level and radial lines on the local system.

Response:

(a) The data and calculation was posted on the AESO website shortly after the filing on December 13, 2006 of the additional analysis of bulk system data provided as Appendix D to the AESO’s 2007 GTA. The data, in two large Excel workbooks, is available on www.aeso.ca by following the path Tariff > Current Applications > 2007 Tariff Application > Additional Information. If a stakeholder is unable to access the workbooks from the AESO website, please contact April Walters at (403) 539-2463 to arrange for a CD containing the workbooks.
(b) The quoted statement was not based on detailed numerical analysis of the bulk and local systems, but on the following more general observations:

- The 2006 Transmission Cost Causation Update (provided as Appendix C to the AESO’s 2007 GTA filed on November 3, 2006) determined very similar costs classifications for each function — namely, on an 81.5% demand- and 18.5% energy-related basis for the bulk system, and on an 82.5% demand- and 17.5% energy-related basis for the local system.
- Costs classified as demand-related for both the bulk system and the local system should be recovered on a non-coincident peak basis.
- The distinction between bulk system and local system is not well defined, and three approaches to functionalization were utilized in the original Transmission Cost Causation Study (provided as Appendix B to the AESO’s 2007 GTA filed on January 31, 2005) with very similar results.
- Bulk and local system facilities are both utilized to provide service to multiple customers, and both transport large volumes of electricity over long distances.
- Bulk and local system facilities must both provide sufficient capacity to accommodate loads under both normal and post-contingency conditions.
- For both bulk and local systems, a variety of factors contribute to maximum stress on individual transmission components.
- The characteristics of facilities initially functionalized as bulk system may change over time such that the facilities are later functionalized as local system.

(c) The principal differences between the bulk and local systems are as follows:

- Transmission planning of the bulk system is somewhat more complex, as more contingencies and criteria must be considered, and the impact of failure on the bulk system has wider reaching implications than that of failure on the local system.
- Bulk system facilities are utilized to provide service to a greater number of customers than local system facilities.
- Bulk system facilities generally transport larger volumes of electricity over longer distances than local system facilities.

Inter-ties to other jurisdictions would be considered part of the bulk system as they generally provide benefits to all transmission users.

As discussed in the response to Information Request TCE.AESO-020 (a), system access service through a connection to the transmission system provides access to exchange electric energy and ancillary services, and is not differentiated by the actual physical system facilities associated with a specific service.

Interconnections with generators, where the facilities are owned by a TFO, are functionalized as bulk system regardless of the actual voltage level of the facilities.

Radial lines are generally not included in the local system cost function. Radial lines are typically functionalized as point of delivery facilities, together with the substations they serve. Both the bulk system and the local system are primarily comprised of looped, not radial, facilities.
Preamble: The AESO states:

Recovery of system costs in this manner thus allows the bulk system and local system costs to be recovered through a single system charge with billing capacity and usage components. This provides a simpler rate and, in the AESO’s opinion, provides a better signal that customers can respond to and manage. A rate with a combined system charge also better aligns with the AESO’s contribution policy which differentiates only between system-related and customer-related costs.


Request:

(a) In deciding to combine the recovery of bulk system and local system costs into a single system charge, please indicate the amount of weight the AESO has placed on:

   (1) AESO administrative benefits of a simpler rate
   
   (2) Benefits to AESO customers of a simpler rate

(b) Please provide details to support the AESO claim that the combined charge provides a “better signal that customers can respond to and manage.” Include in the response any expected savings on the transmission system in the short term and long term from the proposed rate that results from this “better signal”.

(c) Please explain how this rate better aligns with the AESO’s contribution policy which differentiates only between system-related and customer-related costs when the customer contribution policy only relates to POD costs and potentially local system costs (for radial lines) and does not reflect bulk system costs for loads.

Response:

(a) The AESO’s primary consideration in proposing a single charge to recover both bulk and local system costs was the provision of a better price signal to customers. A secondary consideration was alignment with the AESO’s customer contribution policy.

   The AESO placed little weight on AESO administrative benefits, as the AESO billing system can accommodate either both costs separately or combined and administrative benefits would be minimal.

(b) The AESO initially considered the bulk and local charge under the 2006 DTS rate in comparison to the system charge under the proposed 2007 DTS rate. The AESO considers a single demand ($/MW) charge based on billing capacity to provide a clearer
price signal than two demand charges where one is based on coincident demand and the other is based on billing capacity.

The AESO also considered retaining bulk and local charges for the proposed 2007 DTS rate. The AESO again considered a single demand charge of $1,176.00/MW of billing capacity to provide a clearer signal that two demand charges of $830.00/MW of billing capacity for the bulk system and $346.00/MW of billing capacity for the local system.

(c) The customer contribution policy in the AESO’s Terms and Conditions defines both customer-related costs (in Articles 9.3 (a) and (b)) and system-related costs (in Article 9.3 (c)).

Under the contribution policy, customer-related costs generally include costs related to the substation and associated radial line serving the customer, and are covered by investment up to the maximum allowed by the investment function. The same costs are represented in the point of delivery function in the cost causation study underlying the AESO’s rates. As a result there is very good alignment between average customer-related interconnection costs and costs recovered through the POD charge.

Also under the contribution policy, system-related costs are included in TFO costs and recovered over all customers through other components of the DTS interconnection charge. The two-part contribution policy (distinguishing between customer-related and system-related components) is mirrored by a two-part DTS interconnection charge (with distinct POD and system charges).
Preamble: The AESO states:

“Radial line costs were found to correlate well to line length, and poorly to DTS capacity.”


Request:

Please provide the correlation details in Excel spreadsheet format to confirm this statement.

Response:

As part of the preliminary analysis, the AESO investigated a large number of variables in an attempt to identify those variables with potential correlative relationships. The variable analysis included the determination of a possible correlative value between radial line costs and DTS capacity. As identified in the Customer Contribution Study, the relationships with the highest correlative values were compiled as part of the study.

The Excel spreadsheet provided as Attachment TCE.AESO-025 demonstrates the low correlative value between radial line costs and DTS capacity. The data used for this analysis is reproduced from Appendix G – Customer Contribution Data. The corresponding line function for this data is:

\[ y = 2.120M - 0.010M \times MW \], with a correlation factor of 0.001.

The spreadsheet also reproduces the relationship between transmission line lengths and line costs. The corresponding line function for this data is:

\[ y = 0.534M + 0.071M \times km \], with a correlation factor of 0.845.
Preamble: The AESO states:

“Radial line costs exhibited much weaker correlation with DTS capacity”


Request:

Please provide the correlation details in Excel spreadsheet format to confirm this statement.

Response:

Please see the response to TCE.AESO-025.
Preamble: The AESO states:

The observed scatter of total project costs as a function of DTS capacity is not unreasonable when the lack of correlation of radial line costs to DTS capacity and the moderate correlation of substation costs to DTS capacity are considered. Radial line costs will add to the data scatter, but the AESO notes that the moderate correlation of substation cost to DTS capacity indicates inherent scatter in the data even when radial line costs are excluded. The AESO attributes the variability of substation costs to different substation configurations, varying geography and construction conditions, and different levels of complexity for each project.


Request:

Please provide the correlation details in Excel spreadsheet format relied on for the statement the “moderate correlation of substation cost to DTS capacity” and provide the degree of correlation that does exist when radial line costs are excluded.

Response:

The requested information is provided in the attached Excel spreadsheet, 2007-01-24 AESO 2007 GTA – IRs Att TCE.AESO.027 – Sub and DTS Capacity. The correlation factor for substation cost to DTS capacity is 0.314.

When radial line costs are excluded from total project costs, results show a correlation factor of 0.480.
Preamble: The AESO states:

In Decision 2005-132 concerning the Review and Variation of the Customer Related POD Charge in the AESO’s DTS rate, dated December 6, 2005, the EUB stated:

In Decision 2005-096, the Board made it clear that it considered cost causation to be the primary criterion that should be used in rate design. The Board continues to hold this view. While the Board considered cost causation to be the primary criterion to be used in rate design, it is not the only criterion to be given consideration. The Board also made it clear that some consideration should be given to other criteria, including “rate shock”.

... The AESO notes that the views of the EUB summarized above are consistent with the rate design principles provided in section 4.2 of this Application.


Request:

(a) Please provide from a review of Board decisions the range of increases in rates that the EUB has historically considered “rate shock” when rates were bundled with generation, transmission and distribution. Provide a list of the decisions relied upon.

(b) In the “bundled rate” world of integrated electric utilities, does the AESO agree that transmission costs were approximately 20% of large industrial rates and approximately 10% of retail distribution rates? If no, please provide estimates of more appropriate percentages of costs.

(c) Please apply the level of rate shock determined in response to (a) above to a typical bundled large industrial rate and to a typical bundled retail distribution rate estimated in (b) above to estimate what percentage increase in unbundled transmission costs would be required to trigger rate shock under measures used in the bundled world.

(d) Identify how many PODs have rate increases in excess of the amounts estimated in (c) above comparing 2006 to 2007.

Response:

(a) Although the Board has clearly identified “cost causation” as the main criterion for consideration in rate design (2005-132), “rate shock” remains an important secondary consideration. In the context of “rate shock”, the AESO reviewed the following Board

In U99034 (page 40), the Board stated that “the overall increase in revenue over that collected from existing rates is kept at less than 10% for every class, by adjusting as required the “residual” DISCO Services amount to be recovered from customer classes. (The Board notes that individual customers may see more than a 10% increase if their usage characteristics warrant.)” This view of the Board is confirmed in Decisions 2000-11, 2000-15, and 2000-26.

In Decision 2000-60 (page 30), the Board’s view was:

In order to partially mitigate the magnitude of the rate increase, the Board has stipulated that the maximum increase to any rate class for the period September 1, 2000 to October 31, 2000 will be limited to 25%. Consequently, by utilizing a rate class specific rider methodology, the Board has approved increases of less than 25% (5% to 18%) for six rate classes and increases of 25% for the remaining six rate classes effective September 1, 2000.

In Decision 2003-19 (page 117) the Board notes:

Energy costs can vary widely by customer depending on how a customer acquires its supply. Energy charges are effectively passed through at 100% revenue to cost, however the level of the charges will vary so the percentage of the bill that relates to energy versus wires costs will not be uniform between customers. Therefore the Board does not consider that energy costs need to be included in the calculation of revenue to cost ratios and percentage rate increases.

The Board’s view, expressed in Decision 2005-96 (page 27) was:

With respect to gradualism or rate shock concerns, the Board notes that the AESO has stated that DTS rates will rise by 66% in total, largely due to the legislative requirement that load pay for all wires costs. Regardless of the rate design chosen, DTS customers will see significant increases in their AESO billings. The Board points out, however, that this relates to AESO billings only. In the past when the Board has considered rate shock, the Board has considered the effect an increase will have on a customer’s total bill. The Board continues to believe that this is the most appropriate manner in which to assess rate design proposals. Only this approach allows the Board to keep bill impact in true perspective.

Finally, in Decision 2005-132 (page 2), the Board noted the following concern regarding rate shock:

The new evidence received from the AESO in the Refiling and Supplementary Filing revealed that the impact on the monthly bills for low load customers of 5 MW or less, absent an ability to factor in a drop in an STS rate, was substantial and could be in excess of 400%. Accordingly, the Board considered that in view of the new evidence that the AESO had submitted as part of its Supplementary
Refiling, the IR responses of October 28, and the comments of individual customers such as Baymag and OxyVinyls Canada, that some customers may indeed suffer some unreasonable level of rate shock and that relief may be warranted.

In the context of these decisions, rate shock could be defined as a total increase of not more than 25% within a particular rate class. The logical extension of this is that increases in transmission charges that result in a total increase of more than 25% could be considered rate shock.

(b) The AESO does not agree and suggests that in the “bundled rate” world, transmission costs were approximately 10% across rate classes.

(c) Given the answers in (a) and (b), transmission costs would have to increase by 250% in order to increase a “bundled” bill by 25%.

(d) When comparing 2006 to 2007, one POD has a rate increases in excess of the amounts estimated in (c) (i.e. 250%). Furthermore, only two PODs have increases in excess of 200%.
Preamble: The AESO states:

(a) Bill impacts should be assessed based on changes from 2005 to 2007 rates rather than from 2006 to 2007 rates. Although bill impacts are traditionally assessed for a change from current rates to proposed rates, the AESO considers that unique aspects of the current situation warrant assessment over two rate changes (from 2005 to 2006 rates and from 2006 to 2007 rates). The circumstances include:

- the significant restructuring of the DTS rate in the AESO’s 2006 tariff and, to a lesser extent, in the proposed 2007 tariff;
- the significant increases to some bills arising from the AESO’s 2006 tariff; and
- the specific relief offered by the EUB to small DTS services being limited to the 2006 test year.


Request:

(a) Does the AESO agree that bill impacts when comparing changes from 2005 to 2007 can also create “rate shock” for customers just as they can for customers when comparing their rates from 2005 to 2006? If no, please provide a full explanation.

(b) Does the AESO agree that rate impacts from 2006 to 2007 would be largely mitigated if the AESO maintained cost classifications, functionalizations and allocations for bulk and local systems on a basis similar to 2006, while still allowing for POD level investment changes, rate level changes (to reflect total cost of services changes) and other changes to the tariff such as changes to the terms and conditions? If no, please provide a full explanation.

(c) While the AESO indicates at page 29 that terminating the cap at the end of 2008 provides three years notice (2006, 2007 and 2008), does the AESO agree that if the Board decision on the 2007 tariff is rendered late in 2007, this will only provide a little over one year’s formal notice of rate increases and therefore the cap should be extended to 2010? If no, please provide a full explanation.

Response:

(a) The AESO considers there is a fundamental distinction between comparing bill impacts from 2005 to 2006 and from 2005 to 2007. The distinction is that from 2005 to 2006 the rate change happened in a single step and customers experienced one bill increase, while from 2005 to 2007 the rate change will happen in two steps and customers have already experienced the majority of the increase in the first step. This affects the consideration of suddenness or unexpectedness generally associated with rate shock.

*The current phrase used by many utility commissions is “rate shock” or “bill shock” referring to the customer’s sudden awareness of large rate increases....*

*An agency will attempt to protect ratepayers from sudden increases and instead introduce a change in rates only gradually.... Movement towards a cost-based rate design is important to many commissions, but non-cost factors affecting rates are “equally important,” and avoiding rate shock is “a primary ratemaking goal,”....*

Rate shock may therefore not exist for rate impacts from 2005 to 2007, if a large increase was already experienced from 2005 to 2006 (when rate shock would have existed) and a small increase would be experienced from 2006 to 2007. The rate shock would not exist because the element of suddenness or unexpectedness has been removed.

(b) Rate impacts would generally be mitigated by maintaining the same functionalization, classification, and allocation of costs. However, in the case of the AESO’s 2007 GTA, this would come at the expense of providing the cost causation basis which satisfies the primary rate design principles of provision of appropriate price signals and fairness, objectivity, and equity, as discussed in section 4.2 of the Application.

In addition, the AESO expects the very small PODs which receive the largest increases under the AESO’s proposed DTS rate would continue to receive extremely large increases under the suggested scenario of maintaining the basis for bulk and local system charges while adopting the proposed POD charge. As noted by the AESO on page 24 of section 4 of its Application, smaller PODs receive large increases primarily due to the fixed component of the proposed POD charge. The adoption of the proposed POD charge would continue to result in large increases for very small PODs, even if the basis for bulk and local system charges continued unchanged from 2006.

(c) The AESO does not agree. As explained on page 28 of section 4 of the Application, the AESO understands that large bill impacts are unacceptable to stakeholders primarily because they make it difficult for a business to plan for, budget for, and react to changes in transmission costs. This is generally consistent with the element of suddenness or unexpectedness associated with consideration of rate shock discussed in part (a) above.

The final 2006 DTS rate design was significantly different from that proposed in the AESO’s 2006 GTA, and was approved in December 2006 after a refiling in September 2006. Some stakeholders were not involved in the refiling process, and some customers only became aware of the 2006 changes to the DTS rate after the refiling or after the final rate’s approval. The resulting rate change was therefore unexpected by some customers and relatively sudden.

Several of those customers subsequently participated in the AESO 2007 rates consultation. The AESO has also published much more information on the design of the DTS rate, and included the bill impact on every POD as part of the AESO’s application. The AESO therefore believes that customers are more aware of the changes in the DTS
rate and the potential impact of those changes, and considers that the element of suddenness or unexpectedness has been greatly reduced in its 2007 tariff application.

Substantial changes to the DTS rate would have been indicated, at the latest, by the changes implemented in the 2006 rate on January 1, 2006. An expiry of the rate cap no later than December 31, 2008, will provide customers with three years’ notice of changes to the rate no matter when the 2007 tariff is actually approved and implemented. The AESO therefore does not at this time support the extension of the rate cap beyond 2008.

Having said that, the AESO also recognizes that the final DTS rate approved as a result of this proceeding could be materially different from that applied for in the 2007 GTA. In that event, the element of suddenness or unexpectedness may be reintroduced, and the AESO suggests it might be appropriate to reconsider bill impact at that time. Regardless, customers will still have received three years’ notice of changes to the rate, and further consideration may not be necessary.
Preamble: The AESO states:

(d) Bill impacts should be addressed through appropriate rate structures to as great an extent as possible. The AESO considers that the proposed DTS rate structure has mitigated rate impact to many individual PODs through the considerations incorporated into the rate design. Where rate impact remains a concern and is of a level which requires relief, the AESO proposes that POD-specific relief be offered.


Request:

Has part of the AESO’s impetus to change the DTS rate structure been to mitigate the “rate impact to many individual PODs”? Please explain.

Response:

No. The AESO’s impetus to change the DTS rate structure has been to adhere to the cost causation basis which satisfies the primary rate design principles of provision of appropriate price signals and fairness, objectivity, and equity, as discussed in section 4.2 of the 2007 GTA.
Preamble: The AESO states:

…The requirement for such a service was raised during the AESO's 2005-2006 GTA proceeding itself (summarized on page 30 of EUB Decision 2005-096), and the AESO committed to examining the requirement for a backup or standby service in its next tariff application.


Request:

(a) Is it the AESO's understanding that the Alberta government generally supports the development of cogeneration for serving domestic load and for export? Please cite references in support of AESO's views. If no, please provide a full explanation.

(b) Does the AESO believe that cogeneration can be economically attractive and environmentally responsible due to the very high efficiency and low emissions when compared to other non-renewable natural resources? If no, please provide a full explanation.

(c) Is it the AESO’s opinion that the Alberta government’s policy on generation generally supports all forms of generation? If no, please provide a full explanation.

(d) Is it the AESO’s understanding that the AIES has in the past and will continue in the future to recognize, within limits, that different forms of generation have unique and different circumstances requiring different treatment? Please cite any examples, either historical or currently under consideration. If no, please provide a full explanation.

(e) Please confirm that (1) the AESO has devoted significant staff resources to addressing problems related to wind generation in southern Alberta including approval of new transmission, (2) the AESO has devoted considerable resources to advancing the 500 kV north south transmission line to largely accommodate new coal-fired generation in the Edmonton area and (3) devoting considerable resources to solving standby tariff problems in support of cogeneration would be appropriate. If no, please provide a full explanation.

(f) Is the AESO aware of any jurisdiction where a Standby tariff (or its equivalent) is designed to grant rate relief not entirely justified by cost causation but where such a tariff is also designed to encourage or incent cogeneration development? If so, please cite references.

(g) Does the AESO agree that the rate principle described as the “provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service” could recognize the “benefits” that cogeneration brings to AESO Customers and Alberta in general? If no, please provide a full explanation.
(h) Is it the AESO’s understanding that the unique requirements of cogeneration type loads lead to standby tariffs, or their equivalents, in many jurisdictions? Please cite all jurisdictions studied, whether they employ a standby tariff or not and if so how that standby tariff is designed. If no, please provide a full explanation.

(i) Does the AESO agree that, with respect to the AESO’s Long Term Adequacy Committee review of generation supply in Alberta, there are concerns that future generation will be inadequate to meet load and that it therefore follows that transmission tariffs should not create any unnecessary barriers to entry for generation development? If no, please provide a full explanation.

(j) Does the AESO agree that onerous and/or high-cost standby tariffs may be perceived as barriers to entry for generators to develop in Alberta? If no, please provide a full explanation.

Response:

(a) The AESO is not aware of any preferential support by the Alberta government for the development of cogeneration. For example, the Alberta Department of Energy’s June 6, 2005 policy paper titled *Alberta’s Electricity Policy Framework: Competitive – Reliable – Sustainable* states on page 27:

> As illustrated in Figures 2 and 3, the majority of the capacity additions since 1996 were gas-fired units (primarily cogeneration), with Genesee 3 a recent notable exception. Although the prospect of being able to sell energy into a competitive market can contribute to a decision to build co-generation, the primary driver is “within the fence” of the co-generation owner, to ensure that the plant will meet its processing needs. The Department is of the view that such plants are typically not installed to be timely in meeting the supply requirements of the electricity market.

(b) The AESO agrees with the Department of Energy’s view, as stated in part (a) above, that for a cogeneration plant “the primary driver is ‘within the fence’ of the co-generation owner, to ensure that the plant will meet its processing needs.”

(c) The AESO agrees that the Alberta government’s policy does not favour particular forms of generation. The Alberta Department of Energy’s policy paper referenced in part (a) above states on page 47:

> The Department does not support one type of generation over another but rather allows competitive market forces to determine the appropriate generation mix (e.g. no fuel use policy).

(d) In accordance with section 8(1) of the Transmission Regulation, the AESO must:

> [take] into consideration the characteristics and expected availability of generating units, plan a transmission system that is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the Act when all transmission facilities are in service, and
(ii) is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy referred to in section 17(c) of the Act when operating under abnormal operating conditions;

(f) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in-merit electric energy referred to in clause (e)(i) and (ii) can be dispatched without constraint;

The AESO agrees that the characteristics and expected availability of generating units were also considered in the past, although such considerations were made in the context of a vertically integrated electric industry prior to 1996. Despite similar considerations, decisions with respect to the specific generating units installed may therefore have been different prior to industry restructuring than in the current competitive generation market.

(e) The AESO considers that it has devoted appropriate and considerable resources to:
   • addressing concerns with respect to wind generation in southern Alberta,
   • advancing the north-south 500 kV project to carry power from northern Alberta to central and southern Alberta, and
   • developing a rate that fairly, objectively, and equitably allocated costs to and recovers costs from backup services.

The consideration of backup service is described in section 4.6 of the AESO’s 2007 GTA.

The AESO also notes that these three undertakings are quite different in nature, and devoting an appropriate level of resources to each does not imply devoting an equal level of resources to each.

(f) The AESO is aware that such tariffs have been implemented in some jurisdictions. For example, Rate Structures for Customers With Onsite Generation: Practice and Innovation by L. Johnston, K. Takahashi, F. Weston, and C. Murray (National Renewable Energy Laboratory, Golden, Colorado, December 2005) states (p 63):

   In many states, DG [distributed generation] ratemaking is being taken up as part a broader effort to develop a set of state policies to promote DG and capture its expected economic, environmental, and reliability benefits for customers, utilities, and society as a whole. These anticipated benefits go beyond a strict evaluation of electric system costs and benefits of a customer’s individual installation. State regulatory agencies may want to design rate treatments to affirmatively promote distributed resources, including clean DG.

The report identifies Massachusetts, New York, and Rhode Island as states with rates developed, at least in part, to achieve public policy goals.

(g) The AESO considers that, in the context of the transmission tariff, reflecting all costs and benefits refers to all costs and benefits relating to the transmission system. If any “benefits” of cogeneration are external to the transmission system, it would be
inappropriate to incorporate such benefits into the rate design of the AESO’s tariff (at least in the absence of specific legislative direction to do so).

(h) The AESO understands the requirements of onsite generation, whether utilizing cogeneration or other technologies, frequently leads to the development of backup or standby rates. For example, *Rate Structures for Customers With Onsite Generation: Practice and Innovation* by L. Johnston et al. states (p 7):

> In New York, Massachusetts, and Oregon, utilities used existing cost-of-service studies to determine DG [distributed generation] standby rates. The availability, or lack, of specific cost analysis has been cited as a concern in a number of jurisdictions.

(i) The Long-Term Adequacy Working Group has not assumed there will be inadequate generation to meet load. The Working Group’s objective, to date, has been the implementation of metrics to monitor the balance between supply and demand, and, if the supply-demand balance becomes a concern, to ensure bridging actions exist that will address the concern. Please refer to the response to Information Request TCE.AESO-034 (b) for additional information.

(j) Please refer to the response to Information Request TCE.AESO-034 (b).
Preamble: The AESO states:

The “partial-requirements” category which is not accommodated under existing rates is backup or standby service (a).


Request:

(a) Please confirm that existing rates do not include a standby service for generators.

(b) Does the AESO agree that this lack of an appropriate rate may be viewed by generation developers as a deterrent to further generation development? Please explain why or why not.

Response:

(a) As explained on lines 5-7 of page 33 of section 4 of the AESO’s 2007 GTA, “Although there is no special provision for backup service in the current AESO tariff, such use of the transmission system is not prevented in any manner (except by capacity or other system constraints).”

(b) In general, the AESO’s tariff is intended to provide appropriate and equitable price signals based primarily on cost causation as it pertains to system access service. In setting the transmission tariff, the AESO does not have a role in either promoting or deterring generation development. The AESO’s perspective is that customers, whether load or generation, generally view the lack of an appropriate rate as a deterrent to development, if the rate that would apply is higher than an appropriate rate. The AESO’s examination of backup service during the development of its 2007 GTA led to the conclusion that the proposed DTS rate is appropriate for backup or standby service, as it satisfies the rate design principles discussed in section 4.2 of the Application.
Preamble: The AESO states:

Initial consideration suggested minimal costs are caused by short-duration, infrequent use of the transmission system. The AESO speculated that loads which occur for less than 10% of the time and for only a few times a year would not affect either long-term or short-term planning decisions, assuming a small number of such loads in any specific planning area, and reasonable non-coincidence of such loads in an area.


Request:

Please describe what additional information or analysis not already in the application led the AESO to change its perspective on costs and planning decisions with respect to standby loads.

Response:

Section 4.6 of the AESO’s GTA provides a complete explanation to it’s position concerning standby loads.
The AESO states:

…the AESO estimated that 1,500 to 2,000 MW of load could potentially request backup service and incur minimal cost for utilizing it.

Reference: Section 4 – 2007 Rate Design, Page 34 of 53.

Request:

(a) Please provide the details on how the amount of potential backup service was estimated.

(b) Was any consideration given to mitigation methods to insure only loads associated with cogeneration or generation facilities would be able to request backup service?

(c) Does the AESO have an estimate of the amount of load required to backup generation?

Response:

(a) Please refer to the response to Information Request BR.AESO-004.

(b) As discussed on page 34 of section 4 of the AESO’s 2007 GTA, the AESO considered conditions or restrictions on eligibility but considered the characteristics of backup service (short duration, infrequent, and unscheduled usage) could be exhibited both by loads associated with cogeneration or generation facilities and by low load factor load service. The AESO therefore concluded that, from a transmission system perspective, there is no cost or operational basis for distinguishing between backup service to a generator and intermittent operation of a load service.

(c) Please refer to the response to Information Request IPCAA.AESO-047 (b).
Preamble: The AESO states:

Stakeholders also suggested that concerns with concurrent use of backup service or concentrated use in a geographic area could be addressed through operating procedures or technical solutions. The AESO is currently developing transmission constraints management rules which may curtail services to contracted capacities in areas already impacted by concurrent use above contract. The draft operating procedure is relatively complex and has received some stakeholder opposition. The AESO suggests that reducing the charges attributable to backup service will worsen the constraints issue and increase the reliance on complex management protocols.

Reference: Section 4 – 2007 Rate Design, Page 34 and 35 of 53.

Request:

(a) If customers were to agree to operate within surplus transmission capacity on both the bulk and local system and to curtail load should this capacity become constrained, would the AESO agree in principle that they should receive a rate that provides them some relief in cases where no costs were incurred for transmission development to serve their loads? If no, please provide a full explanation.

(b) In areas with multiple co-generators (i.e. Fort McMurray, Cold Lake), if the customers were to work together to share the requirement to curtail load rather than build additional transmission, would the AESO agree in principle that those customers should receive a rate that provides them relief from some transmission costs related to transmission development? If no, please provide a full explanation.

Response:

(a) The AESO considers that the proposed rate provides a reduction of about 55% in DTS system charges for a backup service, compared to DTS system charges for a “normal” service, as discussed in section 4.6.3 of the AESO’s 2007 GTA. The AESO further considers that such charges provide a fair, objective, and equitable allocation of costs to backup services. The AESO therefore does not consider that further reductions are warranted for a rate applicable to backup service.

(b) The AESO suggests that recognizing the coordination of load between customers would effectively totalize the customers’ services. The primary premise of totalized services is that both services could be physically served through a single point of delivery. If so, physical totalization may be a more appropriate approach, as the customers themselves would determine appropriate responsibilities and cost-sharing arrangements, rather than require the AESO to become involved as a third party to a customer arrangement.
Preamble: The AESO states:

…A 5% duration threshold was chosen as a reasonable representation of backup loads based on three considerations:

- It approximates the point where the load duration curve becomes more vertical than horizontal (that is, where the tangent to the curve becomes greater than 45° from the horizontal).
- The transmission system is generally planned on a 95% probability of load coincidence.
- A similar level has been used in backup rate determinations in some other jurisdictions (Arizona, for example).


Request:

(a) Please further explain how the graph in Figure 4.6.1 was created and include a detailed definition of what is meant by “Average Percentage of Peak Line Load”, which is the label on the Y-axis.

(b) Please explain the significance of the point on the curve where the curve becomes more than 45 degrees.

(c) Please explain the significance of the statement that “The transmission system is generally planned on a 95% probability of load coincidence.”

Response:

(a) Please refer to the response to Information Request IPCAA.AEOS-044 (c).

(b) In general, where the load-duration curve is more-or-less horizontal it reflects a high-frequency or long-duration loading level, and where the load-duration curve is more-or-less vertical it reflects a low-frequency or short-duration loading level. A 45° tangent represents the threshold between more-or-less horizontal and more-or-less vertical.

(c) Please refer to the response to Information Request ADC.AEOS-029.
Preamble: The AESO states:

Assuming that line loading below the 5% duration threshold represents normal loads, about 72% of peak line loading, and about 72% of transmission system costs, can be attributed to normal loads. Similarly, assuming that line load above the 5% duration threshold represents backup loads, about 28% of peak line loading, and about 28% of transmission system costs, can be attributed to backup loads. Compared to the costs attributed to normal loads, backup loads should be attributed $28% \div 72\% = 39\%$ of normal costs.


Request:

(a) Please provide data in Excel format to demonstrate that the top 5% of the line loading is caused by backup loads that are coincident with the top 5% of peak line loads.

(b) Please provide the AESO assumptions (load size, number of outages, duration of outages, etc.) used in determining the need for and the costs associated with a standby rate.

(c) Please provide data showing the correlation between cogeneration facilities planned maintenance shutdowns and their associated standby loads during those same periods.

Response:

(a) Please refer to the response to Information Requests IPCAA.AESO-045 (a-b) and IPCAA.AESO-046 (b).

(b) The AESO made no specific assumptions other than those summarized in section 4.6 of the Application.

(c) The AESO did not analyze the correlation between scheduled maintenance shutdowns and associated standby loads. However, the AESO understands that the associated standby loads would occur at the time of scheduled maintenance shutdowns (for those partial-requirements services categorized as scheduled maintenance services) such that there would be very high correlation.
Preamble: The AESO states:

The Northeast Alberta Transmission Development stakeholder presentation on October 2, 2006 indicated the region’s transmission system was being developed to support 815 MW of normal operating load and 425 MW of backup load. In this case the transmission system is being planned to carry an additional 425 MW ÷ 815 MW = 52% capacity above normal operating load which is attributed to backup load. The Northeast Alberta Service Requirements also forecast a total 1,100 MW of backup load to be interconnected. In this case, backup load will be about 1,100 MW ÷ 815 MW = 135% of normal load.


Request:

(a) Please confirm that the AESO is not planning to build bulk transmission system in Northeast Alberta to serve the cumulative sum of all of the firm DTS contract capacity in the Fort McMurray area and instead will build based on a reduced percentage of that cumulative DTS by applying a probabilistic method that allows for some but not all generation to be out of service at any point in time. If yes, what is that approximate reduced percentage? If no, please provide a full explanation.

(b) Does the AESO agree that the Fort McMurray area is, over time, likely to become a net load center due to lower cogeneration development compared to load growth? If no, please provide a full explanation.

(c) Does the AESO agree that the lower amount of cogeneration development in Fort McMurray is affected, among other factors, by the lack of transmission out of the area and by the lack of a competitive standby tariff? If no, please provide a full explanation.

Response:

(a) Yes, the AESO does not intend to plan the bulk system into the northeast for the cumulative sum of all the DTS contract capacity. Consistent with general planning practices, an appropriate level of diversity will need to be considered. The transfer capacity into the northeast has not been determined at this time. This determination is part of the Northeast Stakeholder Consultation Process and the development plan is expected to be filed with the EUB in the 2nd quarter of 2007.

(b) No, the AESO’s present forecast information indicates that the Fort McMurray area is likely to become a balanced system by 2016 where load and generation will be evenly matched. However, it is also expected that this area will swing significantly back and forth from being a load center to being a net generation area. This is due to the local area generation being driven by the needs of oilsands processing instead of providing power to the grid.
(c) No, as part of the Northeast Stakeholder Consultation Process, the AESO's discussions with developers in the Fort McMurray area was to solicit information to ensure that the future transmission system development would be adequately sized to meet their future needs. While not emphasized in those conversations, the AESO understands that adequate transmission is a concern in all generation development. Standby tariffs were not raised as a significant issue in those discussions, and the AESO considers the proposed DTS rate to be appropriate for standby service.
Preamble: The AESO states:

Normal load at the AESO is about 80% load factor (average AIS loading) and incurs a two-year 90% ratchet. Over a year, a 1 MW normal load would incur the following system wires charges under the proposed DTS rate:

\[
\begin{align*}
1 \text{ MW} & \times 12 \text{ months} \times $1,176.00/\text{MW/month} = $14,112.00 \\
1 \text{ MW} & \times 80\% \text{ load factor} \times 8,760 \text{ hours} \times $2.42/\text{MWh} = $16,959.36 \\
\text{Total annual charge} & = $31,071.36
\end{align*}
\]

A 1 MW backup load which operated for 5% of the time during the year would incur the following system wires charges:

\[
\begin{align*}
1 \text{ MW} & \times 1 \text{ months} \times $1,176.00/\text{MW/month} = $1,176.00 \\
1 \text{ MW} & \times 90\% \text{ ratchet} \times 11 \text{ months} \times $1,176.00/\text{MW/month} = $11,642.40 \\
1 \text{ MW} & \times 5\% \text{ load factor} \times 8,760 \text{ hours} \times $2.42/\text{MWh} = $1,059.96 \\
\text{Total annual charge} & = $13,878.36
\end{align*}
\]

The annual charge for 1 MW of backup load would be about 45% of the annual charge for 1 MW of normal load.


Request:

Please prepare a schedule comparing the full DTS charges (Interconnection Charge, Operating Reserve Charge, Voltage Control Charge and Other System Support Services Charges) that a typical standby (backup load) customer (40 MW, 5% load factor based on one 2 week planned turnaround and the rest of the use based on random forced outages) and that an equivalent “normal load” customer (40 MW, 85% load factor) would have been charged for service under both the 2005 and 2006 tariff as well as under the proposed 2007 tariff.

Response:

Please see attached Schedule TCE.AESO-041.
Preamble: The AESO states:

The AESO also examined the need for scheduled generator maintenance service beyond that which is currently accommodated under DOS Term. Currently such scheduled maintenance is eligible for DOS Term only if the customer would reduce load rather than incur the increased ratchet levels that would apply under the DTS rate (as stated in the AESO’s Demand Opportunity Service Business Practices). The AESO proposes modifications to DOS Term in this application to accommodate scheduled generator outages which should address this customer need. Additional information on the revised DOS rates is included in the following section 4.7 of this application.

Reference: Section 4 – 2007 Rate Design, Page 39 of 53

Request:

(a) Please confirm if existing or potential standby loads required for generators expressed support for this proposal given that it does not include forced outages? If yes, please indicate which stakeholders provided support.

(b) Does the AESO agree that a typical generator seeking a standby tariff is looking for a rate that supports both planned and unplanned generation outages? If no, please provide a full explanation.

Response:

(a) In response to a request for comments on its 2007 tariff proposals as presented on September 21, 2006, the Dual-Use Coalition, EPCOR, IPCAA, PPGA, and TransCanada Energy expressed support for the AESO’s proposal that "Relaxing the DOS Term qualifying criteria to make it available for all scheduled maintenance service is appropriate."

ADC indicated it was indifferent to the proposal. No stakeholder who provided comments expressed opposition to the proposal. Seven other stakeholders who provided comments did not express any position on that particular proposal.

Stakeholders comments may be viewed on the AESO website at www.aeso.ca by following the path Tariff > Current Consultations > 2007 Rates > AESO 2007 Rates Consultation > 2006-10-18 AESO 2007 Rates Consultation - Stakeholder Comments (Revised).

(b) The AESO understands that generators may require both backup or standby service as well as scheduled maintenance service, as those "partial-requirements services" are defined in section 4.6 of the AESO’s 2007 GTA. The AESO also understands that generators may make decisions with respect to their utilization of either service, based
on economic and other considerations with respect to taking such service from the transmission system compared to alternatives.

The AESO has proposed relaxing the DOS Term qualifying criteria to accommodate scheduled maintenance service, and has reviewed the proposed DTS rate to ensure appropriate charges apply to backup service. The combination of both approaches provides both partial-requirements services to customers at appropriate rates, and should enable generators to make appropriate economic choices regarding utilization of such services.
Preamble: The AESO states:

The tariffs of the AESO and its predecessors have included opportunity service rates for load customers since the electric industry was deregulated in Alberta in 1996. The AESO’s current tariff provides three Demand Opportunity Service (DOS) rates: DOS 7 Minutes, DOS 1 Hour, and DOS Term.


Request:

(a) Does the AESO agree that given that the constraints on the transmission system in Alberta appear to be increasing at least until major transmission upgrades are commissioned (500 kV north south, SW Alberta, etc.), that it would be prudent for the AESO to be encouraging customers to consider DOS status and to make DOS criteria as flexible as reasonably possible? If no, please provide a full explanation.

(b) Has the AESO considered creating more DOS style rate options that would provide more operating flexibility in operating the transmission system? If no, please provide a full explanation.

Response:

(a) The AESO considers that the DOS rates proposed in its 2006 tariff provide an appropriate price signal for DOS rates and incorporate appropriate DOS criteria. Please refer to the responses to Information Requests TCE.AESO-044 (d) and TCE.AESO-046 (c) for additional information.

(b) Please refer to the response to Information Request TCE.AESO-046 (c).
Preamble: The AESO states:

(b) DOS customers should pay a portion of the fixed costs associated with the interconnection system component of the DTS rate, as a contribution to fixed costs to reduce the level of average rates charged to other customers.

(d) DOS customers should pay the variable costs associated with the operating reserve component of the DTS rate. The operating reserves carried by the AESO are determined in accordance with Western Electricity Coordinating Council (WECC) and North West Power Pool (NWPP) requirements regarding replacement of generating capacity and energy lost due to forced outages of generation or transmission equipment. As generation cannot be identified as serving opportunity loads, DOS customers contribute to the AESO’s requirement to carry operating reserves, and should therefore pay those costs like other load customers.

Reference: Section 4 – 2007 Rate Design, Page 40 of 53

Request:

(a) Please confirm that fixed and variable costs do not necessarily become demand and energy costs on a one-to-one basis in a cost of service study. If no, please provide a full explanation.

(b) Please confirm that the fixed costs of a transmission system are relatively high, about 80% or more of total wires cost. If no, please provide a full explanation. What portion of the transmission system is a fixed cost for each functionalized category?

(c) Please confirm that the Average and Excess method advocated by the AESO in Section 4.5 of the Application converts some of the fixed costs of the transmission system into demand and usage costs, not just demand costs. If no, please provide a full explanation.

(d) Please confirm that the AESO knows the amount of DOS load on the system in any given hour. If no, please provide a full explanation.

(e) Explain why the AESO must identify specific generation facilities as serving opportunity loads in a power pool such as the Alberta power pool. Also explain why a portion of the generation available from the pool cannot be assigned to DOS customers to match their load in any given hour thereby reducing the AESO’s needs to carry operating reserves for those customers.
(f) Please confirm that WECC Rules permit the AESO to either reduce the required reserves for a willing interruptible export curtailable in ten minutes or to include an interruptible export as non-spinning reserve? If no, please provide a full explanation.

(g) Please confirm that the contingency reserve required by the system would not have to increase for an export load that was willing to be curtailed in ten minutes? If no, please provide a full explanation.

**Response:**

(a) Confirmed.

(b) Confirmed. A transmission system generally comprises primarily fixed costs for all of its subfunctions (bulk system, local system, and point of delivery).

(c) Confirmed. A portion of the transmission system costs which are classified as demand-related are allocated on an energy basis using the average and excess demand approach. Please refer to the response to Information Request EnCana.AESO-012 (b) for additional discussion.

(d) Not confirmed. The AESO knows the amount of all approved DOS contracts applicable at any given point in time. The individual DOS customer may or may not be taking DOS even though the customer has an active approved DOS contract. The AESO does not have remote real time visibility of all PODs for all DOS customers.

(e) Operating reserve requirements are calculated by determining the system firm load responsibility. The firm load responsibility is calculated in part by using a summation of generation. This is because real time data is available from nearly all of the generation. Conversely a much smaller percentage of real time load metering is available. If DOS loads were excluded from contributing to operating reserve requirement, the generation designated to serve the DOS load would have to be known. A portion of generation could be designated for DOS load, however, the AESO believes that it is appropriate to charge DOS customers for operating reserve requirement since DOS loads are not curtailed when the system requires operating reserves to be dispatched.

(f) Confirmed. Please refer to PWX.AESO-020 (a) and (b).

(g) Confirmed. In order for an export load to be interrupted in 10 minutes for contingency reserves, the party receiving the energy would be required to carry sufficient reserves for the full amount of the transaction. Please refer to PWX.AESO-020 (a) and (b).
Preamble: The AESO states:

The resulting minimum costs attributable to DOS customers are summarized in Table 4.7.2.

<table>
<thead>
<tr>
<th>DTS Rate Component</th>
<th>Fixed</th>
<th>Variable</th>
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<tr>
<td>Interconnection – POD</td>
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<td>-</td>
<td>-</td>
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<tr>
<td>Operating Reserve</td>
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<td>2.29</td>
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<tr>
<td>Voltage Control</td>
<td>-</td>
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</tr>
<tr>
<td>Other System Support</td>
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<tr>
<td>Total</td>
<td>-</td>
<td>4.71</td>
<td>4.71</td>
</tr>
</tbody>
</table>


Request:

(a) Referring to your response to the previous question, please reproduce Table 4.7.2 based on actual variable costs incurred by the AESO to support DOS loads.

(b) Please reproduce Table 4.7.2 based on actual variable costs incurred by the AESO to support DOS loads per part (a) to this question and if DOS loads were curtailed whenever sufficient operating reserves were not available.

Response:

(a) The AESO considers that Table 4.7.2 as provided above appropriately represents the variable costs attributable to DOS loads.

(b) As explained in the response to Information Request TCE.AESO-044 (e), DOS loads are not curtailed when the system requires operating reserves to be dispatched.
Preamble: The AESO states:

The AESO does not currently have any DOS 1 Hour customers. If such loads did exist and were required to be curtailed in a transmission emergency, the AESO would need to issue notice well in advance of expected need to maintain the 1 hour notice period. This might result in DOS 1 Hour customers being curtailed more frequently than DOS 7 Minutes customers. (Note that DOS 1 Hour notice actually occurs in Step 6 of AESO OPP 801, prior to DOS 7 Minutes notice in Step 7.) However, the AESO currently has only four DOS customers, and comparing curtailment frequencies between services is not practical.

During stakeholder consultation the AESO proposed that, based on the similar nature of curtailment provisions and qualifying criteria for DOS 7 Minutes and DOS 1 Hour, the DOS 1 Hour rate be eliminated in this Application. Stakeholders objected to this termination, and on further consideration the AESO accepts their recommendation that the rate remain available.

The AESO therefore proposes to include in the DOS 1 Hour rate a contribution to fixed costs equal to 50% of the $/MWh amount associated with the DTS interconnection system fixed component. This represents a minimal contribution to costs as DOS customers incur no contract minimum or ratchet costs in hours in which they do not schedule capacity, and approaches the $2.00/MWh price differential between the current DOS 7 Minutes and DOS 1 Hour rates. This amount is shown in Table 4.7.3 to determine the DOS 1 Hour rate.

Reference: Section 4 – 2007 Rate Design, Page 42 and 43 of 53 .

Request:

(a) If the AESO had DOS 1 hour load customers and they were curtailed more often than DOS 7 minutes customers, why would the AESO charge more for DOS 1 hour load customers given the lower standard of service?

(b) Please provide the curtailment frequencies in the last two years of DOS 7 minutes and DOS term customers.

(c) Are there any instances of curtailment that have actually occurred (per (b) above) or that could potentially occur under various contingency conditions where a DOS load could be given more than 7 minutes notice and yet the shedding of the load would be valued from a system operational perspective? Please explain and include instances of two contingencies that are separated by more than 7 minutes.
(d) Is the AESO intending to discourage customer interest in DOS 1 hour by setting a higher price than DOS 7 minutes? If yes, please provide a full explanation.

Response:

(a) In an energy shortfall situation that is not forecastable, DOS 1 Hour load customers have 53 minutes longer to curtail load than DOS 7 Minutes load customers. Therefore the standard of service provided in terms of notice for DOS 1 Hour is greater than the standard of service for DOS 7 Minutes.

(b) Overall there were a total of seven events where DOS was called down in the last two years, for an average frequency of 3.5 DOS curtailments per year. There were active DOS 7 Minutes contracts during each of these curtailments, but no active DOS Term contracts.

(c) Based on a review of the curtailment frequencies in the last two years of DOS 7 Minutes and DOS Term customers, and considering that an event could potentially occur under various contingency conditions, there were no known occurrences where a DOS load could be given greater than 7 minutes notice such that this extension of time would be of some value from a system operations perspective.

(d) The AESO is not intending to discourage customer interest in DOS 1 Hour by setting a higher price than DOS 7 Minutes. As explained in part (a) above, the notice provision is greater and this is reflected in the higher price.
Preamble: The AESO states:

DOS Term includes one qualifying criterion in addition to the DOS 7 Minutes and DOS 1 Hour criteria: the customer may require increased electrical consumption during planned maintenance of an on-site generator and would otherwise reduce load to avoid the ratchet on the standard DTS rate. As with all qualifying criteria, the onus is on the customer to make a convincing case for the use of DOS Term for generator maintenance, and assessing the case that the customer would otherwise reduce load has always been problematic for the AESO. At the same time, the AESO's consideration of the provision of backup service in section 4.6 of this Application resulted in the proposal to relax the qualifying criteria for DOS Term to permit its use for planned generator maintenance.

Although the AESO proposes to relax the qualifying criteria for DOS Term, all DOS loads will continue to be curtailed in accordance with OPP 901 to prevent or alleviate abnormal conditions as listed earlier in this section. DOS remains interruptible, temporary, and available only when there is surplus transmission capacity. Standby use of an unplanned nature, including unplanned outages or derates of a generator, remains ineligible for DOS, including DOS Term. All DOS usage continues to require a qualifying application including system studies.

In extending the availability of DOS Term to all planned generator maintenance, the AESO proposes that the DOS Term price include a component that in effect converts the "system" ratchet charges incurred by loads above contract capacity into a usage ($/MWh) charge which generates equivalent revenue over a typical maintenance period. Assuming annual generator maintenance of two to four weeks (that is, about one month or less), a 1 MW excursion above contract capacity would incur \((1 \text{ MW} \times 1 \text{ month}) + (1 \text{ MW} \times 90\% \times 11 \text{ months}) = 10.9 \text{ MW-months of charges, to be recovered over the four-week period or 672 hours. The charge would be calculated as follows, based on the system demand component of the interconnection charge in the proposed DTS rate.}


Request:

Given that DOS Term “remains interruptible, temporary, and available only when there is surplus transmission capacity”, why does the AESO intend to charge ratchet charges to generators looking for a standby rate? What advantages does this bring to a generator seeking a standby tariff if they are being charged the equivalent of what would be charged for ratchet charges in rate DTS that is providing them with firm service?
Response:

The DOS Term rate does not include ratchet provisions. All charges in DOS rates are $/MWh charges and are incurred only in hours during which DOS capacity is contracted.

However, in establishing the contribution to fixed costs for DOS rates as discussed in section 4.7 of the AESO’s 2007 GTA, the AESO assessed the DOS Term rate an amount equivalent to the “system” ratchet charges for loads above contract capacity on the standard DTS rate. This does not imply a ratchet applies; the equivalent amount was converted into a $/MWh charge in accordance with the opportunity nature of the service.

The AESO notes that DOS Term charges will be less than charges under the standard DTS rate in two circumstances which may be particularly relevant for scheduled maintenance:

(i) if DOS Term service is contracted for less than four weeks per year, and
(ii) if DOS Term service is contracted less frequently than once per year (for example, once every three years for generator turnarounds).
Preamble: The AESO states:

The AESO notes that in consultation 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 understands that in neighbouring jurisdictions the majority of export transactions occur on hourly, monthly, and annual rates, and has therefore proposed hourly and monthly opportunity export rates together with an annual non-recallable rate in this Application.


Request:

(a) Is it the AESO’s intention that hourly transactions can be combined together into a block of hours such as 1 to 7 AM to permit exports transactions that extend beyond one hour? If no, please provide a full explanation.

(b) Is it the AESO’s intention that monthly transactions can be combined together into a block of months to permit exports transactions that extend beyond one month and perhaps as long as one year? If no, please provide a full explanation.

Response:

(a) Yes.

(b) Yes.
Preamble: The AESO states:

The AESO further notes that the proposed addition of multiple export rates with different priorities cannot be accommodated with existing inter-tie scheduling systems used by the AESO. An OASIS (Open Access Same-time Information System) or other system with similar capabilities will be required to accommodate the additional rates, and the rates cannot be implemented before such a system is installed and commissioned.

The OASIS or similar system is required to manage the contracting and scheduling of capacity, allocation of ATC, release of unscheduled capacity, and curtailment of multiple export services on existing inter-ties and merchant interconnections to other jurisdictions. Procedures for these activities will be developed in the AESO’s Operating Policies and Procedures (OPPs) consistent with current practice. OPPs generally include stakeholder consultation in their development, and the current versions of OPPs are publicly available on the AESO’s website.


Request:

(a) What is the estimated time required to install an OASIS or other system with similar capabilities?

(b) When does the AESO expect to initiate installation of and OASIS and what is the cost estimate?

(c) Is it the intention of the AESO to begin work on installing such a system in parallel with the implementation of the rates? If yes, what is the expected completion date?

(d) Has the AESO attempted to negotiate an acceptable arrangement with BCTC for the use of their OASIS and if yes, please advise as to the status of these negotiations?

(e) In the opinion of the AESO, what are the needs that would drive the move to an OASIS?

Response:

(a) The estimated time to install any system is dependent on several factors including the scope of the work and availability of resources. The AESO has used a preliminary estimate of 6 months to implement an OASIS system.

(b) The AESO expects that approval of the rates is a requirement in order to initiate significant expenditures related to this project. Detailed cost estimates are not available
at this time. The AESO included a budgetary cost estimate of $300,000 for this project in the October 5\textsuperscript{th} 2006 “AESO 2007/2008 Business Priorities and Budget”.

(c) If approved, the rates will be implemented when the system is implemented. The AESO intends to begin development of necessary business practices and operating policies and procedures in advance of rate approval. These are required in order to create specifications for the OASIS system.

(d) No.

(e) As stated in the Application in Section 4, page 45, “The OASIS or similar system is required to manage the contracting and scheduling of capacity, allocation of ATC, release of unscheduled capacity, and curtailment of multiple export services on existing inter-ties and merchant interconnections to other jurisdictions.”
Preamble: The AESO states:

(a) XTS rate components are generally set to be equivalent to DTS rate components expressed on a usage basis, except for the interconnection point of delivery (POD) charge.


Request:

(a) Does the AESO agree that for the foreseeable future, e.g. the next 3 to 5 years, the likelihood that customers will be able to book firm exports of any magnitude on a 7 by 24 basis, including on-peak hours, is minimal? If no, please provide a full explanation.

(b) Assuming that the AESO agrees rate XTS is primarily an off-peak rate, please explain why the AESO chose to price XTS at a rate equivalent to the DTS rate?

Response:

(a) The AESO acknowledges that the likelihood that participants can export on a 7x24 basis over the next 3 to 5 years is minimal, however, at the present time there is available export capacity most hours of the day. All exports from Alberta are considered part of the AESO’s firm load responsibility and the AESO carries operating reserves to support these transactions (i.e. all exports from Alberta are firm to the extent they are not subject to constraint or interruption). With respect to the AESO’s proposed export tariffs, “firm” exports (XTS) have a higher priority for scheduling and curtailment than opportunity exports (XOS) but there is no guarantee of availability.

(b) The AESO does not agree that the XTS rate was designed primarily as an off-peak rate.
Preamble: The AESO states:

Although exports would be curtailed before UFLS-connected load under a supply shortfall emergency, UFLS-connected load is also curtailed to maintain the stability of the transmission system in the event of other major system disturbances when exports would not be curtailed. The UFLS Credit compensates load customers for curtailment under more than system-wide supply shortfall conditions. The curtailment of XTS capacity would be more consistent with curtailment of non-UFLS-connected load, and Rate XTS should therefore not receive the UFLS Credit.

Reference: Section 4 – 2007 Rate Design, Page 46 of 53

Request: Over the past 10 years, or shorter period of time if 10 years of data is not available, please provide the number of times that UFLS-connected load has been curtailed under a supply shortfall emergency compared to the number of times a UFLS-connected load has been curtailed to maintain the stability of the transmission system in the event of other major system disturbances.

Response: The UFLS credit provides compensation for automatic load curtailment during system under frequency events. Non-UFLS load which may be shed manually is not intended to be armed for UFLS. However, a portion of non-UFLS-connected load may be a part of the wire owners’ manual load shed program.

The AESO database does not contain sufficient detail to provide the requested information and comparison.
Preamble: The AESO states:

(c) Rate XTS does not include an interconnection POD charge as there are no "customer-related" facilities associated with export service.

(d) A minimum charge based on 90% of scheduled capacity applies to Rate XTS, in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity. This minimum charge is comparable to the 90% ratchet level applied in the determination of billing capacity in the DTS rate.


Request:

(a) Please confirm that there are no local transmission facilities involved that are associated with export service. If no, please provide the details and costs associated with the local facilities associated with export service.

(b) Does the AESO intend to retain its right to curtail ATC during the hour for rate XTS? If yes, please confirm that ratchet charges will be waived if ATC is reduced during the hour and if no, why not.

(c) Please describe all "seams" issues that need to be resolved at the BC – Alberta border for the XTS Rate to be of use to market participants.

(d) Does the AESO intend to include transmission rights with Rate XTS?

(e) Please confirm the amounts of firm export held by BCH Powerex or the BC side of the border (per the BCTC OASIS) and confirm that very little firm export capacity is available for other participants. Also identify the terms of BCH/Powerex firm exports.

(f) Please identify all the benefits, if any, to Alberta exporters of Rate XTS.

Response:

(a) Please refer to the response to Information Request PWX.AESO-008 (b).

(b) Yes. If required, the AESO may curtail ATC during the hour for reliability reasons and this could affect an XTS customer. In an hour where ATC is curtailed and an XTS customer is actually flowing energy, XTS will be billed on a MWh basis (i.e. the XTS customer pays for the service for the time it is used but not for the time it is curtailed). In an hour where ATC is curtailed and the XTS customer does not have scheduled energy, the 90% minimum charge will apply to the capacity that was available in the hour on a MWh basis.
(c) It is common for seams issues to exist between neighbouring jurisdictions offering different transmission services. Seams that may be encountered at the Alberta-BC border include differing timelines for reserving and scheduling transmission, curtailment practices, energy and ancillary service market rules, transmission service priority, differing rates and different ownership of transmission capacity on each end of the intertie. Many of these seams arise as all the jurisdictions that border Alberta have FERC 888 compliant tariffs while the AESO does not. The AESO is confident that the business practices being developed in 2007 through a consultative process with participants will help ensure that the AESO’s export services are useful to participants.

(d) No.

(e) The AESO does not regularly track the transmission service held by participants in neighbouring jurisdictions. Registered users may access this information on the BCTC OASIS.

(f) In practice, XTS is intended to provide participants with a higher priority export service and/or a mechanism for signaling the desire for additional intertie capacity.
The AESO states:

(f) XTS capacity will be curtailed immediately prior to curtailment of non-recallable domestic loads. For example, in a supply shortfall emergency, non-recallable domestic load is curtailed in Step 29 of OPP (Operating Policy and Procedures) 801; XTS capacity would be curtailed immediately prior to Step 29 of OPP 801.


Request:

(a) Please explain why XTS capacity will be curtailed immediately prior to curtailment of non-recallable domestic loads. Include in your explanation if the proposed priorities relate to an “Alberta first” policy, whether they are a function of rate priority only or some other reason(s).

(b) Does the AESO agree that the proposal to base rate XTS on rate DTS suggests XTS customers will receive a lower quality of service as a result of this decision? If no, please provide a full explanation.

(c) Does the AESO agree that a reduced quality of service between customer classes is potential grounds for a differentiation in price, all other factors being the same? If no, please provide a full explanation.

Response:

(a) The AESO is responsible for maintaining reliability and adequacy in Alberta and, as the Balancing Authority within the WECC, also has shared responsibility for managing the reliability of the interconnections. In supply shortfall situations, pro-rata curtailment of exports and domestic loads would result in minimal export volume curtailments which would have no practical benefit to reliability or the management of the supply/demand balance. In effect, XTS is given priority over all services except DTS, including operating the system with reduced operating reserves. XTS is curtailed immediately before DTS because the practice is effective, efficient, and practical.

In addition, non-recallable domestic loads on rate DTS are committed for a minimum 5-year term whereas XTS customers are committed for a minimum 1-year term. In the event that there are many requests for XTS for terms greater than 5 years, the AESO may review the merits of the curtailment policy.

(b) The quality of the service is similar in most respects. However, XTS will be curtailed immediately before DTS for the reasons noted above.
(c) A difference in quality of service, such as curtailment priority, may be grounds for
differentiation in price, among other things.
Preamble: The AESO states:

(b) XOS customers should pay a portion of the fixed costs associated with the interconnection system component of the DTS rate, as a contribution to fixed costs to reduce the level of average rates charged to other customers. The AESO proposes that XOS customers pay the same contribution to fixed costs as DOS customers — that is, the lowest priority XOS rate would include no contribution to fixed costs, while higher priority rates would include a contribution as discussed later in this section.


Request:

(a) Please confirm that XOS, a rate typically only available in off-peak hours and sometimes not available at all, is significantly less firm and therefore a lower quality of service than DOS customers typically receive. If no, provide statistical evidence to support the AESO's position. If yes, please provide the entire justification as to why XOS customers should pay the same rates as DOS customers?

(b) Please confirm that XOS customers are curtailed before DOS customers? If no, please provide a full explanation.

Response:

(a) Not confirmed. At least 100 MW of Available Transfer Capacity (ATC) was available on the Alberta-BC inter-tie for about 80% of the time in the last quarter of 2006.

In addition, an XOS customer is only charged for service in hours in which sufficient capacity exists to accommodate the energy transfer; if ATC is not available the XOS customer is not charged for contracted opportunity export service. Opportunity service is generally never “guaranteed” in any manner, which is reflected in a rate design which includes only variable charges, and only those variable charges reasonably attributable to the provision of the service.

(b) Confirmed for curtailments during a supply shortfall. Under supply shortfall conditions, XOS customers will be curtailed immediately before DOS customers. However, the AESO notes that in supply shortfall conditions, pool price is very high and opportunity exports are unlikely due to the high domestic pool price.

XOS and DOS customers may also be curtailed independently for other reasons. XOS customers may be curtailed for bulk system reliability reasons such as sudden loss of transmission lines or critical generators, or for voltage issues. A DOS customer may be curtailed for similar reliability reasons that could also be initiated on the local system.
serving the DOS customer. In these cases it would be unlikely that both XOS and DOS customers would be curtailed for the same contingency event.
Preamble: The AESO states:

(i) XOS 1 Hour and XOS 1 Month require minimum contract terms of 1 hour and 1 month respectively. For XOS 1 Month, the same level of XOS capacity would be contracted for the full contract term, but would be available only in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity.


Request:

Please confirm that participants will be able to book less capacity than the contracted XOS 1 Month capacity if a smaller amount of ATC exists. If no, please provide a full explanation.

Response:

Confirmed.
Preamble: The AESO states:

Rate XOS 1 Month has scheduling and curtailment priorities higher than XOS 1 Hour and lower than XTS, and should therefore be priced between those rates to reflect a value in accordance with those priorities. The AESO proposes that Rate XOS 1 Month pay the same contribution to fixed costs equivalent to that included in the DOS 1 Hour rate, namely 50% of the $/MWh amount associated with the XTS interconnection system fixed component.

Reference: Section 4 – 2007 Rate Design, Page 49 of 53

Request:

(a) Assuming that the AESO has acknowledged in the response to question 55 that the XOS 1 Month is not comparable to DOS 1 Hour in terms of service levels, please provide a full explanation why the rates are set at the same levels.

(b) If exports are oversubscribed due to constraints on the transmission system in southern Alberta, please explain how the constrained paths are to be allocated among participants seeking to export. Include in your response the AESO’s role in declaring constrained paths, confirmation that the BC – Alberta tie line is a constrained path and the mechanism to identify trigger participants.

Response:

(a) Please refer to the response to Information Request TCE.AESO-055 (a).

(b) The AESO is presently developing business practices to deal with all aspects of export capacity allocation, scheduling, and curtailment in Alberta and will consult with stakeholders on these matters in 2007. The business practices will accommodate the addition of a new inter-tie to Montana, the new export services outlined in the 2007 GTA, and the implementation of an Open Access Same-Time Information System (OASIS), and will be updated over time to accommodate future developments such as the potential implementation of dispatchable inter-ties.

The AESO identifies constrained paths through the use of engineering studies. Please refer to the Transmission Reliability Criteria found on the AESO website.

Trigger participants are normally identified through the AESO’s interconnection process. While the inter-ties have limited capacity and, at times, normal economic operation of import and export transactions will be constrained, the AESO’s interconnection process does not presently apply to inter-ties and the trigger participant concept is not applicable.
Preamble: The AESO states:

During stakeholder consultation on export and import rates the AESO initially proposed to develop rates for export and import service over merchant transmission lines using a point-to-point model (rather than the “network service” model which forms the basis for the export and import rates discussed above). The AESO now proposes for the 2007 tariff that the network service model also apply to merchant services, consistent with other rates provided in Alberta.


Request:

Please confirm that the AESO is not opposed in principle to a point-to-point model and will work with interested stakeholders on a case-by-case basis to develop a mutually agreeable proposal for submission to the AEUB as appropriate.

Response:

The AESO will continue to review and modify its tariff for merchant services as appropriate in consultation with affected stakeholders, as merchant services evolve. If a point to point or other model is appropriate in the circumstances, under applicable legislation, the AESO would not be opposed to it in principle.
Preamble: The AESO states:

The level of the PSC was assessed in detail during the AESO’s 2006 GTA proceeding, with its calculation based upon typical configurations the system would invest in to provide transmission service to a load customer. The EUB approved the level of $660.00/MW/month in Decision 2005-096. The AESO proposes to maintain this level for 2007, adjusted to reflect changes to the POD-related revenue requirement and to align with the structure of the proposed POD charge, as follows.


Request:

Does the AESO agree that in principle the POD-related revenue requirement for a POD wholly owned by a customer should be zero? If no, please provide a full explanation.

Response:

The AESO does not agree. The POD-related revenue requirement includes costs associated with substations, radial lines serving single substations (which on average represent about a third of the cost of interconnection projects), communication equipment, breakers at adjacent substations, and other equipment. Even if a customer owns their own substation, they usually do not own associated radial line and other facilities included in the POD-related revenue requirement.

As well, the POD charge which recovers those costs represents an average rate to be applied to all customers. A customer-owned substation may cost more or less than average, but the customer should still be responsible for a share of average costs as provided for by the DTS rate and the PSC, to ensure fair and equitable treatment in the provision of system access service to all customers.
Note: Information Request number 60 was missing in TCE's original submission.
Preamble: The AESO has made significant changes to the Customer Commitment Agreements and TransCanada wishes to better understand these changes and the reasoning for them.

Reference: Section 6 – Terms and Conditions of Service, Pages 44-47 of 47

Request:

(a) With respect to the definition of Cancellation Costs, please confirm that the costs and expenses are direct and incremental and do not include any amounts for AESO overhead or salaries of permanent staff. Would the AESO consider a change to reflect that the costs must have been reasonably incurred?

(b) If there was more than one customer on the same expanded interconnection, how would costs be allocated?

(c) In the definition of “Material Adverse Change”, why would paragraph (b)(iii) be a trigger if (i) or (ii) are not triggered?

(d) In Section 7(c), why is there no provision for an appeal period?

(e) In Section 7(f), why does this provision extend beyond representations and warranties made in this agreement? Why would the provision not be limited to “material” representations and warranties?

(f) In Section 9, would the AESO consider changing the wording to permit a reasonable period of time, e.g. seven days for payment of the Cancellation Costs? Does the AESO believe that 6% over prime as a penalty would be enforceable in law? Why or why not?

(g) Why has the AESO not included a right for the customer to terminate the Proposed Project, subject to the reimbursement of the Cancellation Costs? [NTD: Is the process by which we enter into the new System Access Agreement set forth in another related agreement or otherwise mandated. If no, do we need a commitment from AESO to enter into the new System Access Agreement upon satisfaction of the appropriate pre-conditions. [sic]]

(h) Is the AESO prepared to insert a provision by which the customer is kept informed of the actual expenditures to date and the estimated project costs? If no, why not?

Response:

(a) Confirmed. The AESO does not consider that additional revisions are necessary. As noted in part (h) below, situations where a project is cancelled and cancellation costs are required to be paid by the customer, supporting detail will accompany the charge when
presented to the customer. Ultimately costs not considered reasonable may be reviewed with the EUB.

(b) Unless project costs can clearly be identified to have been incurred by a specific customer, cancellation costs will be allocated using the ratio of DTS Contract Capacities at the substations as outlined in Article 9.5.

(c) The question concerns the Security provisions of the proposed CCA, and assumes that every event, circumstance or change in the assets or business of a Customer or its Guarantor will result in a similar consequence for the financial condition or ability of that Customer or Guarantor to perform its obligations under any security. If that is in fact the case, then (i) and/or (ii) may well be triggered. However, in the context of the Security provisions, and particularly Section 5, of the proposed CCA, the AESO considers it reasonable to reserve the opportunity to enhance such security in the event that a change in the business or assets of the Customer or Guarantor does not do so.

(d) The proposed CCA is to be governed by and interpreted in accordance with the laws of Alberta (section 20), including those provisions providing for appeals from decisions of the EUB to the Alberta Court of Appeal. It was not thought necessary to make provision in the proposed CCA to rights which exist as a matter of law, and which the AESO must obviously have regard to in respect of Cancellation Events. The AESO would not be opposed to including specific reference to an appeal period in section 7(c), such as by inserting the word "finally" after the word "Board" in section 7(c), to specifically recognize the prospect of challenges to Board decisions.

(e) The provision is specifically limited to "any representation or warranty made or given by the Customer in connection with this agreement...during the term of this Agreement. Such representations and warranties are as found in section 11.

(f) No. Any demand by the AESO for payment under section 9 follows the occurrence of a Cancellation Event. All Customers will be familiar with the terms of the CCA which they execute.

(g) Please see section 7(b), which contemplates that a Cancellation Event includes the termination of the Proposed Project by the Customer.

(h) The AESO submits the information requirements provided under the current interconnection process provides the customer with sufficient detail regarding the interconnection project including project cost information and anticipated expenditure. There are two separate stages in which customers are informed of project details along with cost estimates and provided a corresponding customer contribution calculation (i.e. at the +/- 30% estimate stage and the +20/-10% stage which is just prior to direct assign the work to the incumbent transmission facility owner). The customer also receives the final actual project costs (and corresponding final customer contribution calculation) when the project has been completed. The current process also contemplates that in situations where a project is cancelled and cancellation costs required to be paid by the customer, supporting detail will accompany the charge when presented to the customer.
Preamble:

The new Article 9.9 (b) states: “a Customer materially decreases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement”.

TransCanada understands that the AESO recalculates the Customer Contribution for the original transmission facilities required to interconnect the load to the transmission system. This calculation includes the review of the Customer Contributions paid by the customer for the original interconnection and tariff payments made by the customer for transmission service. The AESO terms and conditions are not clear on this issue and more information is needed to ensure a consistent approach.

The Article 14.3 Excursions During the Notice Period states:

The Contract Capacity immediately following the five year notice period will be the maximum of:

i. the pre-notice Contract Capacity less the reduction of Contract Capacity requested by the Customer; or

ii. the highest Metered Demand during the five year notice period less the reduction of Contract Capacity requested by the Customer.

Customers may provide an additional notice of reduction after an excursion so Contract Capacity will be reduced to previous notice levels.

Separate written notice must be provided reductions or terminations of Contract Capacity at each respective POD and POS at a single transmission station; net reductions will be accepted or effected.

Article 14.4 Payments in Lieu of Notice states:

Customers reducing or terminating their System Access Service Agreements may choose to pay out the Contract Capacity as a lump sum payment:

i. Contract Capacity reduction or termination lump sum payment charges will be based upon the present value of the System Charge as provided in the rate schedule DTS;

ii. The discount rate is as outlined in Article 9.14;

iii. The AESO may re-assess the payment if there are material differences between the requested Contract Capacity and actual capacity.

Reference: Section 7 – Proposed Tariff, page 27 and 37 of 129.
Request:

(a) Please provide an explanation of how the AESO would calculate the adjustment of the customer contribution when a decrease in Contract Capacity is requested by the customer.

(b) Please include in the explanation information on how the AESO analyzes the recovery of the original cost of the transmission facilities during the initial contract term in the System Access Service Agreement.

(c) Please provide an example of the calculation of the adjustment of the customer contribution when a decrease in Contract Capacity is requested by the customer.

(d) How does the AESO manage the changes in Customer Contribution policy from the policy that was in place during the original interconnection versus the current policy? The explanation should include information on the allocation of transmission facilities as system versus customer-related facilities.

(e) If the detailed information on how the Customer Contribution was calculated for the original installation cannot be found, how does the AESO calculate the customer contribution required for termination?

(f) When the customer provides written notice to the AESO to terminate or decrease the contract capacity, can the notice include a provision for potential excursions over the contract capacity?

(g) Can a customer as an example, provide five years written notice to the AESO and use the interconnection for two years and then pay the lump sum payment at the end of the two year period?

(h) The AESO has stated that the lump sum payment will be based on the “present value of the System Charge as provided in the rate schedule DTS”. Can the customer pay the System Charge in the rate schedule DTS for services where the customer contribution has been paid by the customer or is zero and the transmission facilities are no longer required to provide service to the customer?

Response:

(a) When a customer informs the AESO of a contract capacity reduction, the AESO generally adheres to the following steps when recalculating a customer contribution:

• All project information is collected. This generally includes project cost information (i.e. line and substation cost), the original customer contribution calculation including the tariff applied, contractual terms and financial invoice information
• The original customer contribution calculation is reviewed for accuracy
• A new customer contribution calculation is performed with the new contract capacity, which includes a review of the customer, system and optional facilities determination and a recalculation of the investment level based on the contract capacity prior to the notice of reduction and following the notice
• The customer is issued an invoice for any customer contributions owing
• Project information files along with the billing system are updated with the new information related to the service
(b) As noted in (a) above, if as a result of the contribution recalculation any incremental customer contributions are now left owing by the customer, the incremental contribution is collected from the customer.

(c)  

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(d) Please refer to BR.AESO-10 (a).

(e) As outlined in (a) above, the AESO will attempt to gather all the necessary information to perform a buyout calculation including the customer contribution recalculation. In cases where all the information may not available, the AESO employs the following general guiding principles in determining the customer contribution recalculation for the POD related portion of the buyout calculation:

- Project interconnection costs are estimated assuming current dollars and then present valued to the year the facility was constructed
- If no information regarding the contribution policy is available, the current approved contribution policy will be used in the customer contribution recalculation for both the original calculation along with the termination calculation, where any resulting contributions must be paid by the customer

(f) Yes, so long as the customer updates their system access service agreement to reflect the expected excursion amounts and dates in which the excursions are expected to happen.

(g) Yes. The termination calculation would include both the system charge in the DTS rate for the remaining three years along with any customer contribution owing as a result of the customer contribution recalculation.

(h) If the customer continues to take service, all DTS charges for service would continue to apply. If the customer terminates service, the lump sum payment would be required.
Preamble: The proposed tariff states:

Article 9.2 –Payment of Contribution

All Customer Contributions and System Contributions required under this Article 9 as determined at the time the Customer executes the necessary agreements signifying commitment as per the AESO’s interconnecting processes, must be paid by the Customer before the start of construction of transmission facilities to provide the requested service. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.

The AESO appears to be requesting payments for expenditures that have not been incurred by the TFO. As a general business practice industry requests staged payments for the construction of new facilities times such that the payments and costs are balanced. Concerns about the ability of the customer to pay are generally dealt with in credit requirements.

Reference: Section 7 – Proposed Tariff, page 23 of 129

Request:

Please confirm that Article 9.2 allows for the customer to pay for customer contributions as the costs of the construction is incurred by the TFO. If not, explain why customer contributions must be paid before the cost are incurred, particularly where such costs may occur months or even years after the funds are paid to the AESO.

Response:

As stated in Article 9.2, all customer contributions must be paid prior to construction. The AESO flows through the contributions to the applicable TFO. This is consistent with historical practices where other Alberta utilities have collected contributions prior to construction. The payment of the customer contribution prior to construction is a requirement for system access service as outlined in the tariff. The purpose of collecting the customer contribution upfront is not only for financial security considerations but also as a demonstration of commitment in pursuing system access service. The AESO submits this continues to be a reasonable requirement to demonstrate commitment but also a reasonable compliance milestone in the interconnection process and a necessary requirement to maintain AESO and DISCO harmonization.
Preamble: The AESO has relied on the Alberta CPI as provided by Statscan but has failed to demonstrate that the Alberta CPI is representative of the increased transmission facility costs from 1999 to 2007.

Reference: Section 6 – Terms and Conditions of Service, page 30 of 47, Table 5 Appendix F – Customer Contribution Study – Final Analysis

Request:

(a) Please provide a table for the years 1999 to 2007 with the substation name, year of installation, primary voltage, MVA rating of transformer, name of TFO, original and adjusted cost of the substation using the Alberta CPI index.

(b) Please provide a table for the years 1999 to 2007 with the project description, year of installation, primary voltage, name of TFO, original and adjusted cost of the transmission line using the Alberta CPI index.

(c) Using the two tables, please demonstrate that the Alberta CPI is representative of increased costs of substation and transmission lines from 1999 to 2007.

Response:

(a-b) Please see the spreadsheet which accompanies this IR response as attachment TCE.AESO-065.

(c) Accompanying the data provided in the above mentioned spreadsheet, the AESO also included an analysis from which the following tables are extracted. These tables group projects by capacity, in order to determine if there is a cost increase pattern that the AESO could use in order to assess an escalation factor beyond the Alberta CPI. Looking at projects of the same size is intended to remove one of the variables that may otherwise affect costs.

Some of the data suggests transmission project costs are generally increasing over time; however, some of the data equally reveals that year over year project costs are at odds with that assumption. The AESO submits this again highlights the fact there are many variables other than inflation that contribute to the cost for projects year over year, even for projects of similar size, and for specific facilities. It is therefore not possible to isolate just the portion that relates to inflation from the data. The following observations based on Tables 1 and 2 further support this:

From Table 1:

- For the 7.5 MW projects - although the projects have similar overall substation costs, the costs of the transformers and breakers reveal significant variability, that can not be explained by timing or size.
• Projects 80 & 288 - both make use of a single 25 MVA transformer, and both were constructed in 2002, but the costs vary significantly ($650k vs. $435k)
• Projects 130 & 230 – in respect of transformer installation costs, project 230 has primary service from 240 kV, had both a 50 MVA and 200 MVA transformer installed at a cost of $870k in 2004, while the single 50 MVA transformer for project 180, taking service from 138 kV, built in 2001 cost $900k

From Table 2:
• projects 385, 387, 80, 288 and 230 -the $/km cost would suggest that there has been virtually no inflation to transmission line construction costs

As the data does not provide a clear pattern of inflation for comparable facilities, the AESO relied on the most accurate project data available (i.e. the total project and AESO standard facilities costs) and applied an EUB-approved escalation factor (i.e. Alberta CPI) in the derivation of a reasonable investment function in compliance with the EUB's directive.

### TABLE 1 - Original Substation Cost Analysis ($M)

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<tr>
<th>DTS CC (MW)</th>
<th>Project #</th>
<th>Voltage (kV)</th>
<th>Max Tx. (MVA)</th>
<th>No. of Tx.</th>
<th>Years</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>$ Tx.</th>
<th>$ Breaker</th>
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<td>No. of Tx.</td>
<td>Line Length (km)</td>
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Preamble: In order to prepare rate impacts using different rate structures and rate levels than those used by the AESO, the underlying billing data to Appendix E is needed.


Request:

(a) Please provide the underlying billing data to Appendix E in an Excel spreadsheet so that the rate impacts on customer PODs can be determined using different rate structures.

(b) Please provide a spreadsheet that allows intervenors to adjust the functionalization, classification, allocations, billing determinants and other rate design parameters to produce a set of rate impacts that can then be compared with the proposal presented by the AESO.

Response:

(a) Please refer to the response to Information Request IPCAA.AESO-032 (a-b).

(b) The rate calculations provided as section 5 of the AESO’s 2007 GTA comprise a fully-functioning spreadsheet model in which functionalization, classification, allocations, billing determinants, and other rate design parameters can be adjusted to produce alternatives to the proposed rates. Such alternative rates can then be used with the average monthly billing determinants provided in Appendix E to estimate average monthly bills, and therefore bill impacts. Please refer to the response to Information Request IPCAA.AESO-032 (a-b) for additional discussion.
Preamble: The AESO states:

The consultation process in respect of Phase II matters was not designed to necessarily result in consensus among interested parties, and unlike the ABRP the proposals would not be taken to the AESO Board for a decision. It was meant to provide an opportunity for the AESO and stakeholders to jointly assess reasonable tariff solutions in consideration of the varying stakeholder positions.

There appear to be a number of concerns expressed by many stakeholders with the AESO’s proposed allocation of bulk system costs.

Reference: Section 3 – Stakeholder Consultation (Phase II)

Request:

Given the apparent widespread opposition to the use of NCP for allocation of bulk system costs by many stakeholders, does the AESO see merit in keeping the current rate design (i.e. 12 CP) for the bulk system costs for the AESO 2007 GTA and only adjust the rates to reflect changes in cost levels? Please explain.

Response:

As discussed in section 4.3.2 of its Application, the AESO considers that recovering bulk system charges on coincident peaks cannot be justified from a cost causation or fairness perspective. Keeping the current 12-CP design for the bulk system charge would therefore not provide a cost causation basis to satisfy the second and third rate design principles discussed in section 4.2 of the Application, and would be inappropriate.

The AESO also notes that, although several stakeholders oppose the use of non-coincident peak billing for recovery of bulk system costs, not all stakeholders support the use of coincident peak billing for that purpose. The AESO therefore expects that a proposal to continue the 2006 bulk system charge would not be unopposed. In any event, as noted above, the primary consideration is to satisfy the rate design principles.